DIRECT TESTIMONY
OF
JOSEPH M. LYNCH

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JOSEPH M. LYNCH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2017-370-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION WITH SOUTH CAROLINA ELECTRIC & GAS COMPANY ("SCE&G" OR THE "COMPANY").

A. My name is Joseph M. Lynch and my business address is 220 Operation Way, Cayce, South Carolina. My current position with the Company is Manager of Resource Planning.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from St. Francis College in Brooklyn, New York, with a Bachelor of Science degree in mathematics. I received a Master of Arts degree in mathematics, a Master of Business Administration degree, and a Ph.D. in management science and finance, all from the University of South Carolina. I was employed by SCE&G as a Senior Budget Analyst in 1977 to develop econometric models to forecast electric sales and revenue. In 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and, in 1991, I was promoted to my current position of Manager of Resource Planning.

Q. WHAT ARE YOUR CURRENT DUTIES AS MANAGER OF RESOURCE PLANNING?

A. As Manager of Resource Planning, I am responsible for producing SCE&G's forecast of energy, peak demand, and revenue; for assisting in developing the Company's generation expansion plans; and for overseeing the Company's load research program.

Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION") PREVIOUSLY?

A. Yes. I have previously testified on a number of occasions before this Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the economic analyses that the Resource Planning Group prepared at various times over the past decade to assess the comparative economic costs and benefits to customers from completing the project to construct two Westinghouse AP1000 nuclear units at the V.C. Summer site (the "NND Project") compared to the other alternatives for meeting customers' requirements for baseload generating resources. My testimony will also present analyses to quantify the effects that changes in natural gas prices have had on the economics of base load generation. I have previously testified about these matters before the Commission and am sponsoring copies of relevant exhibits from my earlier testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

I. The Resource Planning Process

II. The Initial Decision to Build the V.C. Summer Units 2 & 3

III. Confirmation in Docket No. 2012-203-E

IV. 2015 Comparative Economic Analysis

V. 2016 Comparative Economic Analysis

VI. 2017 Analysis Concerning Abandonment.

I. THE RESOURCE PLANNING PROCESS

Q. DESCRIBE WHAT THE RESOURCE PLANNING PROCESS ENTAILS.

A. Among its other functions, the Resource Planning Group conducts economic evaluations of the relative costs to customers of different strategies for meeting their needs for power generation. These evaluations consider the relevant costs to customers of the alternative strategies being evaluated including fuel costs and operating and maintenance costs for the electric generating system under each strategy and the incremental capital-related costs incurred under each alternative. Because baseload electric generation assets are long-lived assets, these evaluations typically use planning horizons of 40 years. The resulting economic analyses provide an objective economic basis for SCE&G's leadership to evaluate each strategy in light of its cost to customers.

Q. PLEASE DESCRIBE THE PLANNING MODEL USED.

A. SCE&G's resource planning studies begin with PROSYM, which is a standard software package. PROSYM is used throughout the electric industry by system planners and generation dispatchers to determine economic dispatch, which is the dispatch of generating resources that results in the least cost to customers. For planning purposes, PROSYM can be used to model economic dispatch of an assumed set of generating assets hour-by-hour, year-by-year over a 40-year period. PROSYM calculates the fuel costs, environmental costs (*e.g.*, the cost of emissions credits, allowances or taxes), the operating costs and variable maintenance cost for each assumed set of generating resources in each year.

In the next step of the analysis, my group calculates the annual revenue requirements associated with each new capital investment envisioned under a particular resource strategy. We add those capital-related costs to the production costs calculated by PROSYM to derive the total incremental revenue requirements of the particular resource strategy.

Q. HOW DO YOU COMPARE COSTS ACROSS DIFFERENT GENERATION STRATEGIES?

A. Some generation strategies involve adding generating resources with relatively low capital costs initially but with higher fuel or operating costs going forward. These strategies may cost less to finance in the near term but can cost customers more in the long-term. Some strategies involve larger upfront investments in more fuel-efficient generating units. These strategies may be more expensive initially but provide greater benefits over the long-term.

To equalize these timing differences, the cost of operating and financing the system under each strategy is calculated year-by-year over a 40-year planning horizon. The result is converted into a levelized present value of each year's cost to customers during that 40-year period. This levelized present value takes into account both long-term and short-term costs and presents the results of different strategies on a comparable basis.

Q. WHAT ARE THE INPUTS USED IN THE PROSYM PROCESS MODEL?

A. The relevant inputs in the PROSYM model include information about:

1. System loads,
2. Load shapes (the number of hours each year that specific load levels are reached),
3. The available generating units, both existing units and the new units proposed under the specific generation strategy being modeled,
4. The capacity, fuel type and fuel efficiency for the proposed units,
5. The dates new generating units are anticipated to be added to the system, and the dates of any anticipated retirement months of older units,
6. Ramp rates of the generating units (the speed at which generating units can be brought to various levels of production),

7. Availability factors of the generating units (how often the generating units are expected to be off-line or have mechanical or environmental limits on their generating capacity),

8. The fuel costs of units (including emission credits or other environmental costs of burning fuel and disposing of ash or other fuel waste), and

9. The fuel efficiency of existing generating units (how much fuel cost is incurred per megawatt hour (MWh) of energy produced).

For each resource planning strategy, the PROSYM model dispatches the available resources to meet customer hourly demands at the least cost to customers over the 40-year planning horizon. The PROSYM model then calculates the resulting fuel costs, environmental costs and operating and maintenance costs associated with the economic dispatch of generation resources under each generation strategy. These constitute the production costs under each generation strategy.

In the final step of the analysis, Resource Planning adds to those production costs the additional depreciation, financing costs, and other capital-related costs associated with the new generation resources that are being considered under that generation strategy. The resulting cost is levelized over the 40-year horizon using standard present value arithmetic. The levelized 40-year cost of each alternative generation strategy becomes a basis for determining which strategy represents the best choice for customers.

Q. IS THIS PLANNING PROCESS A GENERALLY ACCEPTED METHOD FOR RESOURCE PLANNING?

A. Yes. This modeling approach is widely accepted in the utility industry to determine the relative cost and value of alternative approaches to meeting customers' electricity needs. SCE&G has used this modeling approach for resource planning for many decades.

Q. WAS THIS PLANNING METHODOLOGY USED IN 2006-2008 IN MAKING THE DECISION TO BUILD THE UNITS?

A. Yes. This planning methodology was used in the period 2006 through 2008 to determine how to best and most efficiently meet the growing needs of SCE&G's customers for electric energy and capacity through the coming years. SCE&G presented the results of this methodology to the Commission in Docket No. 2008-196-E. In that docket, SCE&G came before the Commission for a determination of whether it was prudent to undertake the construction of the Units or not. This methodology was also used to confirm the economic benefits to customers from continuing to construct the Units. I presented the results of similar but updated analyses in three update dockets conducted between 2012 and 2016 to verify that continuing to construct the V.C. Summer Units 2 & 3 was in the customers' economic interest. Those proceedings were Docket Nos. 2012-203-E; 2015-103-E; and 2016-223-E.

II. THE INITIAL DECISION TO BUILD THE V.C. SUMMER UNITS 2 & 3

Q. IN 2008, WHAT FACTORS WERE IMPORTANT IN SCE&G'S CONSIDERATION OF GENERATION OPTIONS CHOOSING NUCLEAR GENERATION?

A. In 2008, there were a number of factors which were important in SCE&G's consideration of generation options. At the time, the prices for fossil fuels, including both natural gas and coal, had shown themselves to be highly volatile and quite unpredictable. ***Exhibit __ (JML-1)*** contains a copy of the exhibits that I sponsored in Docket No. 2008-196-E. Exhibit H, at page 11, provides a chart of historical changes in fuel prices. Natural gas had increased from a little over $3.00 per MMBtu in 2002 to over $10.00 per MMBtu in 2005 and had settled at over $8.00 per MMBtu in 2006-2007. Production from on-shore natural gas fields was becoming more and more difficult to sustain and could be supported only by drilling deeper, more costly and uncertain wells. Off-shore production was also requiring wells that were deeper and riskier. Liquified Natural Gas ("LNG") plants were being placed into service not to export domestically produced natural gas, as they are now, but to allow the importation of foreign-produced natural gas to supplement even more restricted U.S. supplies. At the time, the high cost of fuel made it impractical to run combined-cycle natural gas generating plants for extended periods during the year.

At the same time, environmental pressures against coal generation were increasing as were the environmental and regulatory risks of adding new coal plants to meet customers' future generation needs. Older or smaller coal plants that could not be economically retrofitted to meet increasingly stringent emissions standards were being slated for retirement. Nationwide, utilities were becoming more and more reliant on natural gas generation to replace coal generation, which was putting increasing pressure on gas supplies, gas prices and gas pipeline capacity. It takes enormous quantities of natural gas to fuel electric generation at utility scale. In fact, the amount of gas required to replace 100% of the generation represented by Units 2 and 3 is roughly comparable to the annual residential gas sales by SCE&G.

At the same time, pressures to reduce CO_2 emissions from electric generation plants were increasing. Future CO_2 emissions limits in the form of carbon taxes or cap-and-trade programs were widely considered within the electric industry to be probable within a decade or less. Numerous bills were being proposed in the U.S. Senate and House to limit CO_2 emissions. As anticipated in 2008, reference costs for potential future CO_2 charges, as reported in carbon exchanges or as computed by the U.S. Department of Energy, varied from $47.00 per ton to $94.00, the latter being the cost assumed to be necessary to overcome the fuel cost differential as it then existed between coal and natural gas generation. In Docket No. 2008-196-E, these reference costs were presented in ***Exhibit __ (JML-1)***, Exhibit H at page 10.

While CO_2 emission limits would clearly increase the cost of coal generation, they would also significantly increase the cost of natural gas generation. Producing a MWh of electricity by burning natural gas produces 60% as much carbon as burning coal.

In his testimony in 2008, SCE&G presented charts that showed the fuel mix of SCE&G's system under a natural gas scenario (where two combined-cycle plants of approximately 654 MW were added to the system) compared to the nuclear scenario. The result of the combined-cycle natural gas strategy was a system that relied on a single fuel, natural gas, for approximately 42% of its electric generation capacity, and on fossil fuels (principally natural gas and coal) for 79%. Under a nuclear strategy, the generation portfolio would be balanced with coal at 37%, natural gas at 24% and nuclear at 27%. Under the nuclear strategy, in spite of growth in demand for energy, SCE&G's carbon emission in 2021 would be lower than in 1995.

Q. WHAT WERE THE ALTERNATIVE PLANS CONSIDERED IN 2008?

A. The 2008 analyses compared the cost to customers from resource plans based on building Units 2 and 3 to three principal alternative plans: (1) plans that relied on two coal generation plants of similar capacity to SCE&G's ownership portion of Units 2 and 3 supplemented by simple-cycle gas peaking units; (2) plans that relied on adding one, two or three units using combined-cycle gas generation supplemented by simple-cycle gas peaking units, and (3) plans that relied on simple-cycle gas peaking units exclusively. Thus, there were basically four strategies being evaluated: 1) a nuclear strategy; 2) a coal strategy; 3) a combined cycle strategy and 4) a peaker strategy.

Q. WHAT DID THE ANALYSES SHOW?

A. The analyses showed that constructing Units 2 and 3 provided the best contribution to system economy of any alternative under reasonable assumptions about the future fossil fuel prices, environmental regulations and load growth. The nuclear facilities were seen as non-emitting resources and therefore able to protect the environment while at the same time mitigating exposure to the cost of complying with future environmental regulations on CO_2 and other emissions. Nuclear generation also created a more diversified portfolio of generation assets that reduced reliance on fossil fuels and reduced the risk to SCE&G and its customers from the volatility of fossil fuel prices and risks of unavailability.

Q. WHAT WERE THE KEY ASSUMPTIONS IN THESE ANALYSES?

A. In evaluating these four alternatives in a base case scenario, the Company used a consistent set of assumptions related to future fuel costs, environmental compliance costs and other costs. The Company also added sensitivity analyses in which the four scenarios were analyzed under varying assumptions related to these costs. Finally, the Company conducted a qualitative assessment of the alternatives against the strength and weaknesses of the Company's then-current generation fleet, the operating needs of the electric system and the environmental compliance cost risks, fuel cost risks and operational risks inherent in SCE&G's then-current generation mix.

Q. WHAT DID THE ANALYSIS SHOW FOR NATURAL GAS?

A. Coal and peaker strategies were not competitive. The Company evaluated combined-cycle natural gas capacity as a potential economic alternative to the nuclear units. While this was a viable alternative to nuclear generation, adding significantly more gas capacity to the system did not support the goal of fuel diversity, would increase the Company's CO_2 emissions, and would subject the

Company's customers to the volatility of the gas market and the potential costs of complying with future CO_2 emissions regulations.

Q. WHAT WERE THE COMPANY'S PROJECTIONS FOR NATURAL GAS PRICES IN THE MODEL?

A. For the commodity portion of the gas price which is the majority of the cost, the Company relied on the prices of futures contracts trading on the NYMEX as of April 22, 2007. The Company used the trading price through 2010 and escalated the prices by 2.8% to estimate the cost beyond 2010. Transportation costs were added to the commodity price of the gas as well. While gas prices are notoriously difficult to predict, this method was a very conservative but still reasonable approach to predict future prices.

Q. WHAT WERE SOME OF THE ENVIRONMENTAL COMPLIANCE COST ASSUMPTIONS IN THE COMPARATIVE ANALYSES?

A. The costs associated with future CO_2 regulation was a major driver in the comparative analyses. A combined-cycle gas scenario would increase SCE&G's CO_2 emissions by 8,500,000 tons per year or 510,000,000 tons over the 60-year life of a plant as compared to the nuclear generation option. A coal plant scenario would increase SCE&G's emissions by 19,000,000 tons per year, or over 1.1 billion tons of additional CO_2 emissions over a 60-year plant life. These large increases in CO_2 emissions under the coal and combined-cycle gas scenario compared to a nuclear scenario made the future CO_2 compliance cost an important factor in the costs analyses.

Q. CAN YOU GIVE AN EXAMPLE OF HOW THIS CO_2 FACTOR AFFECTED THE ANALYSES?

A. Yes. Future CO_2 emission costs were an important consideration in 2008. The public policy debate reflected a growing consensus that CO_2 emissions should be curtailed through taxes, emission credits, cap-and-trade structures or other approaches.

In factoring in the future costs of CO_2 emissions, scenarios were analyzed using three values for cost of CO_2 emissions: $15 per ton, what was then considered a more realistic $30 per ton (these were the base scenarios), and zero dollars as sensitivity analyses. Using $15 per ton or more beginning in 2012, the analyses showed Units 2 and 3 to be most economical. The combined-cycle generation would cost customers on average $15.1 million per year more than nuclear generation, and coal generation would cost $94.9 million more.

The $15 per ton assumption was considered unrealistically low because a much higher level of CO_2 charges would be required to bring about a significant reduction in CO_2 emissions nationally. Instead, $30 per ton was considered the more realistic assumption. Under that assumption, a strategy based on combined-cycle gas generation was forecasted to cost customers $125.2 million dollars more per year than building the Units, and a coal strategy would cost customers $267.5 million per year more.

The study presented in 2008 included sensitivity analyses using different factors for CO_2 costs, gas prices, demand growth, higher uranium prices, and retirement of existing coal units. In these analyses, combined gas generation emerged as more economical than nuclear only in cases of lower than anticipated natural gas prices and zero CO_2 costs or, in some cases, \$15 per ton CO_2.

Q. HOW DID COAL GENERATION COMPARE TO THE NUCLEAR UNITS OPTION?

A. The analysis showed that coal generation would only be competitive with nuclear if there would be no costs associated with CO_2 emissions. Zero cost for CO_2 emissions was not a reasonable assumption in light of the then current environmental regulations, and the political and environmental climate. However, even if the CO_2 costs were assumed zero, coal still was not the most competitive alternative to nuclear since under a zero CO_2 cost assumption, combined cycle gas generation was less expensive than coal. As the Commission noted in its 2009 Order, the Company's analysis showed that coal generation was not a competitive alternative given the cost of constructing fully environmentally-compliant coal plants, as well as the recent increases in the cost of coal, and the potential costs associated with CO_2 emissions from coal generation.

Q. WHAT WAS THE COMPANY'S EVALUATION OF THE FUTURE DEMAND GROWTH?

A. The Company forecasted that its firm territorial demand would grow 1.7% per year over the next 15 years. This forecast was lower than the historical 2.5% per year retail load growth. This reduced demand forecast was based on the expected expiration of wholesale contracts with the cities of Orangeburg and

Greenwood and the North Carolina Electric Membership Corporation, as well as new federal efficiency standards for heating and air conditioning units, and new federal standards for residential and commercial lighting efficiency. Nevertheless, even considering these factors, new generating capacity was necessary so the Company's reserve margin would not fall below the Company's minimum target range of twelve percent and fall into an unacceptable two percent by 2016.

Q. DID THE COMPANY ACCOUNT FOR LOWER OR HIGHER CHANGES IN DEMAND?

A. Yes. The Company also modeled future load assuming a 0.5 percentage point reduction in annual energy demand growth per year. This reduction in energy growth was a means to test the sensitivity of the model results to greater than anticipated effects on demand due to energy efficiency or the adoption of alternative generation sources like solar. Under these reduced demand scenarios, the model showed that the reduction did not change the need for base load generation or materially alter the comparative value to customers from construction of Units 2 and 3. Under these analyses, the Units were still the most economical option for adding base load generation. If the demand on the Company's system were to grow faster than anticipated, the model showed some increase in the benefits of building Units 2 and 3, but the effect was not great.

Q. DID THE COMPANY EVALUATE ALTERNATIVE RENEWABLE POWER?

A. Yes, the Company evaluated solar, wind, landfill gas and biomass. While there was room in our plans for increased deployment of these generation resources, they were not a feasible alternative for base load generation. For example, at then-current generating efficiencies and wind turbine sizes, it would have required approximately 96 square miles of solar panels or 2,284 off-shore wind turbines to replace the annual amount of energy generated by the two Units for SCE&G and Santee Cooper.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ECONOMIC ANALYSIS.

A. ***Exhibit __ (JML-2)*** contains a copy of my prefiled testimony from Docket No. 2008-196-E. As I mentioned earlier, ***Exhibit __ (JML-1)*** contains a copy of the exhibits that I sponsored in Docket No. 2008-196-E. Using the 40-year planning horizon, the Company calculated the revenue requirements under each scenario, which included the total system production costs and the capital costs for all incremental capacity. The Company also calculated the levelized present worth of each annual stream of revenue requirements and determined the difference in levelized present worth between the nuclear strategy and the alternative strategies under each scenario.

In the first table on page 9 of 11 of ***Exhibit __ (JML-1)*** at Exhibit H, the nuclear strategy is shown to be the lowest cost option for SCE&G's customers over the long run. The gas strategy would cost SCE&G's customers $15.1 million per year more than the nuclear strategy if CO_2 costs were $15 per ton in 2012. With CO_2 at a reasonable, but still low, cost of $30 per ton, the cost advantage of nuclear would be $125.2 million per year. Column three of the table shows a higher natural gas price with CO_2 at $15 per ton produces a nuclear cost advantage of $68.5 million per year.

As shown in Table 2 of ***Exhibit __ (JML-1)***, on page 9 of 11, the analysis was performed assuming unfavorable conditions to the nuclear strategy such as high uranium prices, low gas prices or no CO_2 legislation. Even with high uranium prices, the nuclear strategy was still less costly and only under the scenarios of low gas prices or no CO_2 regulation would the gas strategy or coal strategy be less expensive. However, under the circumstances at the time, higher uranium prices were not expected, and it did not seem reasonable at the time to expect low gas prices or no CO_2 legislation.

SCE&G also analyzed the future retirement of its existing coal plants in three scenarios in the table on page 10 of 11. As shown by the table, by adding nuclear facilities, the Company would be in a much better position to retire some of its aging base load coal plants (which had mounting environmental compliance issues) and to protect our customers from high fuel prices.

The results of the analyses were presented to the Commission in Docket No. 2008-116-E. In Order No. 2009-104(A), the Commission entered detailed and specific findings supporting SCE&G's decision to construct the Units. In its review of Order No. 2009-104(A), the South Carolina Supreme Court found that "based on the overwhelming amount of evidence in the record, the Commission's determination that SCE&G considered all forms of viable energy generation, and concluded that nuclear energy was the least costly alternative source, is supported by substantial evidence." *Friends of Earth v. Pub. Serv. Comm'n*, 387 S.C. 360, 369, 692 S.E.2d 910, 915 (2010).

III. CONFIRMATION IN DOCKET NO. 2012-203-E

Q. AFTER THE COMPANY'S INITIAL DECISION TO BUILD THE UNITS, DID YOU REVISIT THE ECONOMIC PRUDENCY OF CONTINUING TO BUILD THE UNITS?

A. Yes. I prepared a "Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy" (the "2012 Study") which was presented in Docket No. 2012-203-(E). The 2012 Study confirmed the economic benefits to customers from continuing construction of the Units. A copy of this study is attached to my testimony as ***Exhibit __(JML-3)***. My pre-filed testimony in that docket and Exhibits 1-3 to that testimony are attached to my testimony here as ***Exhibit __(JML-4)***.

Q. PLEASE EXPLAIN YOUR 2012 STUDY.

A. The 2012 Study compared the economics of completing the Units as planned versus abandoning them and constructing instead two 614 MW combined-cycle gas plants. The 2012 Study used the same approach to modeling that was used in the 2008 Studies, except with updated information such as the 2012 cost of completing the Units, the then-current capital cost of combined cycle generation, and the then-current natural gas price forecasts The abandonment scenario took into account the cost of terminating the EPC Contract and subcontracts under it, and decommissioning the site, with offsets for monies received from selling equipment, material and other assets.

Twenty-seven separate scenarios were modeled: (1) three natural gas price forecasts; (2) three assumptions as to future carbon emission costs; and (3) three assumptions as to possible rates of growth in electric demands. In each of the 27 scenarios, the cost to customers from completing the Units was less than the cost of abandoning them and replacing them with natural gas baseload generation.

Q. UNDER THE 27 DIFFERENT SCENARIOS, WHAT WERE THE REASONABLE ASSUMPTIONS AT THE TIME?

A. The 2012 Study determined that the most reasonable scenario for planning purposes was the scenario applying the base electric load, 50% higher gas prices and a $30 per ton CO_2 price. This was the most reasonable scenario for two reasons. First, the moderately higher gas price reflected the fact that the SCE&G forecast was very low when compared to the gas price forecast issued by the federal Energy Information Administration ("EIA"), which is a division of the Department of Energy. In addition, given the very low gas prices in 2015, there was very little room for gas prices to go significantly lower. The greater probability was that future gas prices would be higher than forecasted. In addition, the base case gas forecast used by SCE&G was intended to provide a conservative view of natural gas price growth as a base for assessing other assumptions.

A modest price of $30 per ton for CO_2 was determined to be the most likely CO_2 cost. By that time, the EPA had made a finding that CO_2 emissions endangered human health and the United States Supreme Court had ruled that in light of such a finding, the EPA was required to regulate CO_2 emissions. The $30 per ton assumption was lower than the cost used by the Federal Government in assessing the social cost of CO_2 emissions when evaluating the net impact of new regulatory action. The study also assessed the effects that variations in future electric demand might cause for the analysis. Those variations could result from increased energy efficiency or renewable resources being added to the system. These reductions in demand on our generation resources did not have a material impact on the sensitivity analysis.

Assuming that natural gas prices would be consistent with the EIA forecasts and that future regulations or statutes would impose a $30 per ton cost on CO_2 emissions, and further assuming the base case load growth assumption, cost to customers would be reduced by $290 million per year by completing the Units compared to abandoning them and replacing them with natural gas generation. Assuming the very low base gas assumption, the cost reduction for customers would be $175 million per year under the other assumptions.

Q. WHAT WAS YOUR CONCLUSION IN 2012 BASED ON THE UPDATED ECONOMICS?

A. The economics study clearly demonstrated that it was in customers' economic interest for the nuclear construction to continue. The Commission granted SCE&G the relief requested in Docket No. 2012-203-E. The South Carolina Supreme Court affirmed the Commission's ruling in all respects in *South*

Carolina Energy Users Comm. v. South Carolina Elec. & Gas, 410 S.C. 348, 764 S.E.2d 913 (2014).

IV. 2015 COMPARATIVE ECONOMIC ANALYIS

Q. AFTER YOUR 2012 STUDY, DID YOU HAVE AN OPPORTUNITY TO REASSESS THE COMPANY'S CONTINUATION OF BUILDING THE UNITS?

A. Yes, I did. In 2015, SCE&G came before the Commission in Docket No. 2015-103-E to request approval of an updated capital cost schedule and an updated construction schedule for the NND Project. In that proceeding, I presented an update to the 2012 Study (the "2015 Study"). Like the 2012 Study, the 2015 Study compared the impact on costs to customers of two strategies: (1) completing the construction of the Units and (2) stopping construction and replacing the Units with two combined-cycle gas plants of the same size. This 2015 Study is attached to my testimony in this proceeding as ***Exhibit ___ (JML-5)***. My pre-filed testimony in that docket is attached to my testimony in this proceeding as ***Exhibit __(JML-6)***.

Q. WHAT METHODOLOGY DID YOU USE IN THE 2015 STUDY?

A. This 2015 Study used the same methodology and structure as the similar study presented to the Commission in 2012. The two relevant options were analyzed under the 27 scenarios reflecting different assumptions for natural gas prices, CO_2 emissions costs and future load growth on the SCE&G system. The 2015 Study used then current data as to gas prices, load growth estimates, costs to complete the Units and forecasted costs of natural gas to prepare studies comparable to the 2012 Study.

Q. WHAT WERE THE ASSUMPTIONS FOR THE NATURAL GAS PRICES?

A. The 2015 Study used three natural gas price scenarios: the Company's base case forecast of future natural gas prices, a 50% higher gas price and a 100% higher gas price. As a point of comparison, the 2015 Study noted EIA's 2015 Annual Energy Outlook which approximated the 50% higher gas price forecast.

Q. WHAT CO_2 PRICE SCENARIOS WERE MODELED?

A. Similar to the 2012 Study, the 2015 Study considered three CO_2 emission cost scenarios including $0, $15 and $30 per ton emission costs. The $15 and $30 per ton costs were assumed to start in 2020. The $0 and $15 per ton cost were unlikely scenarios given the cost of compliance. Even the $30 per ton was considered likely too low given the federal government's recommended value of $56 per ton in measuring the social cost of carbon in 2020.

Q. WHAT WERE THE RESULTS OF THIS 2015 STUDY?

A. The 2015 Study showed that in all 27 scenarios, including base gas prices and $0 carbon costs, the effect of canceling the Units and switching to natural gas generation increased the costs to SCE&G customers by a significant amount. If the most reasonable scenario of gas prices at base cost plus 50% and CO_2 emissions at $30 per ton was used, canceling the Units and switching to natural gas would increase the cost to SCE&G's customers for electric service by $278 million per year on average over the 40-year planning horizon.

Q. DID YOU RECONSIDER AT THAT TIME WHETHER ANY REASONABLY FORESEEABLE CHANGES IN THE CAPITAL COST OF THE UNITS WOULD CHANGE THE OUTCOME OF YOUR ANALYSES?

A. Yes, I did. As shown on page 9 in ***Exhibit __ (JML-6)***, and as found by the Commission in Order No. 2015-661, using the most reasonable scenario, the future capital costs of the Units would have had to increase by about $3.1 billion above current forecasts to overcome the benefit of $278 million per year from completing the Units at their current cost.[1]

V. <u>2016 COMPARATIVE ECONOMIC ANALYSIS</u>

Q. DID YOU HAVE AN OPPORTUNITY TO REASSESS THE COMPANY'S CONTINUATION OF BUILDING THE UNITS AFTER 2015?

A. Yes, in Docket No. 2016-223-E, I presented an updated economic study similar to the 2015 Study (the "2016 Study"). A copy of the 2016 Study is attached to my testimony as ***Exhibit __ (JML-7)***. My pre-filed testimony in that docket is attached to my testimony in this proceeding as ***Exhibit ___ (JML-8)***.

Q. PLEASE DESCRIBE THE METHODOLOGY USED IN THE 2016 STUDY.

A. The 2016 Study used the same methodology and structure as the similar structure presented to the Commission in 2015 in Docket No. 2015-103-E, and in 2012 in Docket No. 2012-203-E. The 2016 Study, like the previous economic studies, used well-understood modeling techniques that are generally accepted in

[1] All costs are SCE&G's 55% portion of the capital cost of the NND Project unless otherwise stated.

the utility industry as an accurate means to determine the relative cost and value of alternative approaches to meeting customers' electricity needs.

Q. WHAT SCENARIOS WERE MODELED?

A. Once again, two strategies were modeled: (1) completing construction of the Units and (2) terminating construction of the Units and replacing them with combined-cycle gas plants. Twenty-seven scenarios were analyzed using different assumptions concerning natural gas prices, CO_2 emission costs, and future load growth on the SCE&G system.

Q. WHAT NATURAL GAS PRICE SCENARIOS DID THE STUDY CONSIDER?

A. The base case forecast was used as a starting point as before, along with two future gas price scenarios to account for the high volatility of natural gas prices: one with 50% higher prices than the base case and a second with 100% higher prices. The higher prices of gas were deemed very reasonable to model given the supply and demand factors and regulatory factors discussed previously. Additionally, the study also considered the 2016 Annual Energy Outlook from EIA whose gas price forecast closely approximated SCE&G's 50% higher gas price forecast.

Q. WERE THREE CO_2 PRICE SCENARIOS MODELED AGAIN?

A. Yes, the three variations of CO_2 emission cost were $0, $15 and $30 per ton starting in 2025. At that time, the EPA's Clean Power Plan was subject to judicial stay, but for purposes of the study, SCE&G assumed that the EPA's Clean Power Plan would go into effect as written. In the analysis, SCE&G assumed that the State of South Carolina would choose the "rate-based" compliance option in which each electric generating unit would be required to meet an emission rate target. Under a rate-based compliance plan, the new nuclear units count toward compliance and would generate sufficient emission rate credits such that SCE&G would not be required to incur any additional CO_2 compliance costs under the Clean Power Plan.

However, if SCE&G did not complete the Units and built natural gas combined-cycle plants instead, the Company assumed the State would choose the "mass-based" compliance option where an electric generating unit would be allocated a CO_2 emission cap. Under this scenario, SCE&G would be subject to a CO_2 emission limit and incur costs to comply. Because the cost of CO_2 emissions in the future was uncertain, several levels of cost were studied. If the State chose the rate-based compliance option instead of the mass-based option (which was believed to be unlikely), SCE&G and its customers would have been subject to substantially greater CO_2 emissions costs.

Q. DID YOU MODEL LOAD GROWTH SCENARIOS?

A. Yes, as before, we used updated load forecasts and considered three load growth levels: the Company's base case load forecast, a low forecast, and a high forecast, which adjusted the forecasted load plus and minus 5%. As before, the low load scenario was used as a sensitivity analysis and served to show the effect that greater than anticipated energy efficiency gains or greater than anticipated solar generation penetration would have on the economics of the system. However, the base case already included current estimates of energy efficiency gains and solar generation additions. Nonetheless, the load scenarios showed that varying load up or down 5% did not significantly affect the value of the completing the Units.

Q. WHAT WERE THE RESULTS OF THE 2016 STUDY?

A. The 2016 Study showed that in all 27 scenarios, including base gas prices and $0 carbon costs, the effect of canceling the Units and switching to natural gas generation increased the costs to SCE&G customers by a significant amount. If the most reasonable scenario of gas prices at base cost plus 50% and CO_2 emissions at $30 per ton was used, canceling the Units and switching to natural gas would increase the cost to SCE&G's customers for electric service by $374 million per year (compared to $278 million in the 2015 Study) on average over the 40-year planning horizon.

Q. DID YOU ANALYZE THE SENSITIVITY OF RESULTS TO AN INCREASE IN THE COST-TO-COMPLETE THE NUCLEAR UNITS?

A. Yes. My analysis is reflected in exhibit 3 of ***Exhibit ___ (JML-8)***, which shows, based on current circumstances, the amount nuclear construction costs would need to increase in order to achieve a breakeven point between completing the nuclear project and canceling it. Using the most reasonable scenario, which reflected base gas cost plus 50% and $15 per ton CO_2, the future capital costs of the Units would have had to increase by about $3.83 billion above current forecasts to overcome the benefit of $374 million per year from completing the Units at their current cost.

Q. BASED ON THE 2016 STUDY, WHAT WAS YOUR OPINION AS TO WHETHER THE COMPANY SHOULD HAVE TERMINATED CONSTRUCTION OF THE UNITS AND PURSUED A NATURAL GAS STRATEGY TO MEET FUTURE GENERATION NEEDS?

A. It was my opinion that abandoning the construction of the Units and pursuing a natural gas strategy for base load generation needs would not have been economically justified given what was known at that time. This conclusion was based on the relative costs to customers as calculated using planning models that are widely accepted in the utility industry for analyzing the economic impact of alternative generation plans. Those models were reasonably and fairly applied. They indicated that abandoning the Units would have resulted in significantly increased costs to customers. The 2016 Study, which is presented in ***Exhibit __ (JML-7),*** shows that the Company's nuclear strategy remained the most prudent and lowest cost strategy designed to meet customers' needs for base load generation in the future at that time. The 2015 Study and the 2012 Study support the same conclusion. Abandoning construction of the Units would not have been economically justified based on the results of the utility planning models that are widely accepted in the utility industry for analyzing the economic impact of generation plans.

Q. DID YOU ALSO PREPARE A SENSITIVITY ANALYSIS TO HELP QUANTIFY THE ADDITIONAL COSTS THAT WESTINGHOUSE MIGHT HAVE TO PAY TO COMPLETE THE UNITS ABOVE THE PAYMENTS

THAT WESTINGHOUSE WOULD RECEIVE UNDER THE FIXED PRICE OPTION CONTAINED IN THE 2015 AMENDMENTS TO THE EPC CONTRACT?

A. Yes. I also prepared and presented to the Commission a sensitivity analysis showing the potential costs that Westinghouse would be required to assume if SCE&G and Santee Cooper exercised the fixed price option for completing certain remaining scopes of work under the EPC Contract. The sensitivity analysis modeled the expected change in costs based on assumed productivity levels for the principal categories of construction labor at the site: Direct Craft Labor, Indirect Labor, and Field Non-Manual Labor. That study is attached to my testimony in this proceeding as ***Exhibit __(JML-9)***. It showed that if productivity factors did not improve from historical levels, Westinghouse could be required to absorb approximately $1 billion in additional costs to complete the Units if SCE&G and Santee Cooper exercised the fixed price option they had been granted. This amount is above the amount Westinghouse would be paid under the fixed priced option.

VI. 2017 ANALYSIS CONCERNING ABANDONMENT

Q. PLEASE EXPLAIN THE ANALYSES YOU CONDUCTED AFTER THE WESTINGHOUSE BANKRUPTCY WAS ANNOUNCED.

A**.** After the Westinghouse bankruptcy, SCE&G and Santee Cooper developed their own estimate of the cost and schedule for completing the Units independently of Westinghouse. The New Nuclear Development team forwarded this new information to me. It indicated that net of the Toshiba corporate guarantee settlement payment the estimated cost to complete both Units was approximately $1.1 billion more than had been forecasted in 2016.

Based on this new estimated cost to complete data, I conducted an analysis to determine the relative cost to customers from completing the Units compared to the alternative natural gas strategy. These analyses used the updated natural gas costs and load growth forecasts.

The structure of this analysis was the same as the past studies except that only the base load scenario was analyzed. In the past, the high and low load scenarios did not have a meaningful impact on the results. Therefore only nine scenarios were analyzed: three gas price forecasts cross tabulated with three CO_2 cost scenarios. ***Exhibit ___ (JML-10)*** shows the results of this analysis.

Q. WHAT DID THIS ANALYSIS SHOW?

A. Using the scenario of $15 per ton of CO2 and the 50% higher gas prices as the principal metric, this analysis showed that with Santee Cooper as a co-owner, it would still be in customers' economic interest to complete Unit 2 and Unit 3 even without the benefit of the Production Tax Credits ("PTCs"). The levelized 40-year benefit to customers was $52 million per year. Assuming the full value of PTCs was realized, the benefit increased to $131 million per year.

Completing only Unit 2 with Santee Cooper as a co-owner was also shown to be reasonable. Without the PTCs the levelized benefit over a gas strategy was $84 million per year, a little better than completing both Units. Assuming the full value of PTCs was realized, completing Unit 2 only was a little less economic than completing both Units. The levelized benefit was $126 million per year.

Completing Unit 2 without Santee Cooper, *i.e.*, assuming responsibility for 100% of the cost of Unit 2 and abandoning Unit 3, was shown to be uneconomic for customers without the PTCs. The levelized 40-year difference in revenue requirements showed that it would cost customers $99 million per year more than completing a gas strategy. Assuming the full value of PTCs was realized, the project was about breakeven under the $15 CO_2 and 50% higher gas price scenario.

As Mr. Addison testifies, based on this and other information it evaluated, SCANA's Board of Directors determined that the risks of proceeding with construction of Unit 2 without Santee Cooper as a co-owner were simply too great.

Q. IN 2008, WHAT DID SCE&G PREDICT NATURAL GAS PRICES TO BE IN 2020 WHEN UNIT 2 WOULD HAVE GONE INTO SERVICE UNDER THE 2017 CONSTRUCTION SCHEDULE?

A. Using three years of prices on NYMEX Futures Contracts and an escalation rate approximating inflation, SCE&G predicted that the price of natural gas would be $13.128 per MMBTU in 2020. The current (2018) natural gas price is about $2.867 per MMBTU and the forecasted gas price for 2020 in the 50% higher gas price scenario is $4.741 per MMBTU.

Q. IF NATURAL GAS PRICE PREDICTIONS IN 2008 HAD PROVEN TO BE ACCURATE, WOULD IT HAVE BEEN IN CUSTOMERS' BEST INTEREST ECONOMICALLY TO COMPLETE THE UNITS IN 2017?

A. Yes. We have analyzed the economics of completing the Project using the cost and construction schedules that SCE&G and Santee Cooper prepared in July 2017 after the Westinghouse bankruptcy was announced. We also considered the natural gas price predictions that were used at the time the Project was undertaken in 2008. If natural gas price forecasts today were as predicted in 2008, then completing both Units, with Santee Cooper as a co-owner, would have been overwhelmingly beneficial to customers. Even using the low-range carbon emission assumption of $15 per ton, completing the Units would have reduced cost to SCE&G's customers by $413 million per year levelized over the 40-year planning horizon. Had gas prices been half of what was predicted in 2008, then completing both Units, with Santee Cooper as a co-owner, would have reduced cost to customers by $117 million per year levelized over the 40-year planning horizon. The advantage would be much greater if the $30 per ton CO_2 had been an accurate assumption today.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. More than other factors, including construction price and schedule, the change in gas prices and the change in the likely price and timing of carbon emissions fundamentally changed the economics of these Units and led to their becoming uneconomical for customers. Had those factors not changed, completing the Units in 2017 would have been overwhelmingly justifiable and valuable to customers from an economic standpoint. Other factors may have contributed to the change in economics, but these two—gas prices and CO_2 costs—were determinative. Had gas prices and the risk of CO_2 emissions costs not changed, completing the Units would have been strongly in our customers' interests even after the Westinghouse bankruptcy and even with the additional costs that SCE&G and Santee Cooper would have had to bear.

Q. WOULD YOUR ECONOMIC ANALYSIS OF FUTURE COSTS TO CUSTOMERS HAVE JUSTIFIED CANCELING THE PROJECT SOONER?

A. No. Before the Westinghouse bankruptcy, the economic analysis showed that completing the Units was in customers' best economic interest long-term. After the bankruptcy, and when SCE&G and Santee Cooper had prepared their own estimate of the cost to complete the Units, the economic analysis showed that completing one or both Units could well have been in customers' best economic interest long-term. Only when Santee Cooper's board made the decision to suspend the project did the economic analysis indicate that cancelling the project entirely was in customers' best interest.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT G
FORECAST NEED FOR ELECTRIC AND FUEL TYPE

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit G** shows the need of capacity and how SCE&G will meet its 12-18% reserve margin target over the next 15 years. Without the addition of any supply to its existing long term resources of 5,745 MWs, SCE&G's reserve margin would be below its target range currently and fall to 2.0% by 2016. With the addition of 614 MWs of nuclear capacity in 2016, the reserve margin will be 13.0% and with the addition of the second unit in 2019, 16.8%.

2. PROJECTED RESERVE MARGIN

Year	Firm Load (MW)	Reserve Margin Without Additions (%)	(MW) One year Purchase	(MW) Capacity	Reserve Margin With Additions (%)
2008	5,181	10.9	100		12.8
2009	5,123	11.8	25	-19	12.3
2010	5,181	9.9	125	-34	12.3
2011	5,297	7.5	250		12.2
2012	5,416	5.1	375		12.0
2013	5,262	8.2	225		12.4
2014	5,367	6.1	325		12.1
2015	5,472	4.0	450		12.2
2016	5,582	2.0		614	13.0
2017	5,697	-0.1	75		12.0
2018	5,811	-2.0	225		12.4
2019	5,924	-3.9		614	16.8
2020	6,037	-5.7			14.6
2021	6,146	-7.4			12.6
2022	6,258	-9.0		93	12.1

3. EXISTING SUPPLY PORTFOLIO AND EXPANSION PLAN

The table on the following page shows SCE&G's existing supply portfolio and the next page shows the expansion plan.

Existing Long Term Supply Resources

	In-Service Date	Summer (MW)
Coal-Fired Steam:		
Urquhart – Beech Island, SC	1953	94
McMeekin – Near Irmo, SC	1958	250
Canadys - Canadys, SC	1962	405
Wateree – Eastover, SC	1970	700
*Williams – Goose Creek, SC	1973	615
Cope - Cope, SC	1996	420
Cogen South – Charleston, SC	1999	90
Total Coal-Fired Steam Capacity		2,574
Nuclear:		
V. C. Summer - Parr, SC	1984	644
I. C. Turbines:		
**Burton, SC	1961	0
**Faber Place – Charleston, SC	1961	0
Hardeeville, SC	1968	11
Urquhart – Beech Island, SC	1969	37
Coit – Columbia, SC	1969	30
Parr, SC	1970	60
Williams – Goose Creek, SC	1972	40
Hagood – Charleston, SC	1991	88
Urquhart No. 4 – Beech Island, SC	1999	47
**Un-sited ICTs	2008	34
Urquhart Combined Cycle – Beech Island, SC	2002	467
Jasper Combined Cycle – Jasper, SC	2004	852
Total I. C. Turbines Capacity		1666
Hydro:		
Neal Shoals – Carlisle, SC	1905	2
Parr Shoals – Parr, SC	1914	7
Stevens Creek - Near Martinez, GA	1914	9
*Columbia Canal - Columbia, SC	1927	3
Saluda - Near Irmo, SC	1930	206
Fairfield Pumped Storage - Parr, SC	1978	576
Total Hydro Capacity		803
Other: Long-Term Purchases		25
SEPA		33
Grand Total:		5,745

* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and Columbia Canal is owned by the City of Columbia. This capacity is operated by SCE&G. ** Burton (27MW) and Faber Place (8 MW) gas turbine units are currently in non-run status and will be unavailable indefinitely. Two 17 MW un-sited ICTs will replace this lost capacity.

SCE&G Forecast of Summer Loads and Resources - 2008 COL

	YEAR	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Load Forecast																
1	Gross Territorial Peak	5165	5082	5140	5256	5375	5471	5576	5681	5791	5906	6020	6133	6246	6355	6467
2	Less: Demand-Side Mngt	234	209	209	209	209	209	209	209	209	209	209	209	209	209	209
3	Net Territorial Peak	4931	4873	4931	5047	5166	5262	5367	5472	5582	5697	5811	5924	6037	6146	6258
4	Firm Contract Sales	250	250	250	250	250										
5	Total Firm Obligation	5181	5123	5181	5297	5416	5262	5367	5472	5582	5697	5811	5924	6037	6146	6258
System Capacity																
6	Existing	5745	5745	5726	5692	5692	5692	5692	5692	5692	6306	6306	6306	6920	6920	6920
	Additions															93
7	Peaking/Intermediate															
8	Baseload									614			614			
9	Other		-19	-34												
10	Total System Capacity	5745	5726	5692	5692	5692	5692	5692	5692	6306	6306	6306	6920	6920	6920	7013
11	Firm Annual Purchase	100	25	125	250	375	225	325	450		75	225				
12	Total Production Capability	5845	5751	5817	5942	6067	5917	6017	6142	6306	6381	6531	6920	6920	6920	7013
Reserves With Demand Side Managment																
13	Margin	664	628	636	645	651	655	650	670	724	684	720	996	883	774	755
14	% Reserve Margin	12.8%	12.3%	12.3%	12.2%	12.0%	12.4%	12.1%	12.2%	13.0%	12.0%	12.4%	16.8%	14.6%	12.6%	12.1%
15	% Capacity Margin	11.4%	10.9%	10.9%	10.9%	10.7%	11.1%	10.8%	10.9%	11.5%	10.7%	11.0%	14.4%	12.8%	11.2%	10.8%
Reserves Without Demand Side Management																
16	Margin	430	419	427	436	442	446	441	461	515	475	511	787	674	565	546
17	% Reserve Margin	7.9%	7.9%	7.9%	7.9%	7.9%	8.2%	7.9%	8.1%	8.9%	8.0%	8.5%	12.8%	10.8%	8.9%	8.4%
18	% Capacity Margin	7.4%	7.3%	7.3%	7.3%	7.3%	7.5%	7.3%	7.5%	8.2%	7.4%	7.8%	11.4%	9.7%	8.2%	7.8%

EXHIBIT H

CONTRIBUTION TO SYSTEM EFFICIENCY AND FUEL TYPE

Combined Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order
Public Service Commission Docket No. 2008-196-E

1. INTRODUCTION

This **Exhibit H** provides information concerning the contribution that the proposed Virgil C. Summer Nuclear Station (VCSNS) Units 2 & 3 (the Facilities or Units) will make to the economy and reliability of the integrated electric system that serves the energy needs of SCE&G's customers and the people of the State of South Carolina. This exhibit also reviews various alternative sources of electric generation capacity and energy considered by SCE&G in choosing the proposed AP1000 Advanced Passive Safety Power Plants (AP1000) as the units to construct as VCSNS Units 2 & 3.

2. SYSTEM ECONOMY AND RELIABILITY

These nuclear facilities will serve system reliability because they will provide needed capacity as shown in **Exhibit G**. In addition SCE&G has more than twenty-five years experience operating a nuclear facility and has demonstrated its ability to operate a nuclear plant efficiently and reliably.

System economy is served by the addition of these nuclear facilities because:

- These nuclear facilities are the most economical form of generation to add under reasonable assumptions about the future.
- These nuclear facilities meet the Company's need for more base load capacity.
- These nuclear facilities are non-emitting resources and therefore serve to protect the environment while at the same time mitigating exposure to the cost of complying with future environmental regulations.
- These nuclear facilities support the need for fuel diversity in SCE&G's capacity mix.
- Renewable power, increased demand side management (DSM) and potential energy efficiency gains are not capable of replacing the need for more base load generation; however, they could fit nicely into the expansion plan by displacing some of the purchased power currently shown in the plan.

These matters are discussed in more detail below.

Regarding the Need for Base Load Capacity

The Company's need for base load capacity can be seen in the following table which shows the historical levels of base load capacity in SCE&G's resource mix, its current mix and the 2020 mix with and without these nuclear facilities. Base load capacity is defined as capacity which is intended to run at least 65-75% of the time in a given year. Historically on SCE&G's system only nuclear and coal capacity would meet this definition.

Percent of Base Load Capacity in Resource Portfolio				
1980	2000	Current	2020 with VCSNS Units 2 & 3	2020 Without VCSNS Units 2 & 3
68	74	56	63	45

As shown in the above table, SCE&G has maintained its base load capacity in the 68%-74% range historically. In part because of environmental pressures related to coal, SCE&G has added more gas capacity in recent years resulting in a 56% ratio of base load to total capacity which is low for our system. Clearly there is a need for additional base load capacity, that is, capacity that can generate energy at low cost.

This need for base load capacity is exacerbated by the age of SCE&G's existing base load plants. The table below shows the percent of base load capacity that is more than 40 years old currently and in 2020 with and without these nuclear facilities.

Percent of Base Load Capacity Over 40 Years Old			
2000	Current	2020 with VCSNS Units 2 & 3	2020 Without VCSNS Units 2 & 3
11	23	46	64

While no particular plant has been identified for retirement, the Company does expect to have to retire some capacity during the 40-year planning horizon evaluated in this filing.

Regarding Natural Gas Capacity
SCE&G has evaluated natural gas capacity as a potential economical alternative to these nuclear facilities. However as shown in the following table, adding significantly more gas capacity to the SCE&G system does not support the goal of fuel diversity and would subject SCE&G's customers to the volatility of the gas market at an unacceptable level.

% of Total Capacity	Current Mix	2020 with VCSNS Units 2 & 3	2020 Without VCSNS Units 2 & 3
Nuclear	11	27	9
Coal	43	37	37
Gas	30	24	42

In addition, the volume of gas that is required to replace the electrical output of these nuclear facilities is substantial and certainly would require investment in gas infrastructure.

The following table illustrates this point.

Illustration with Volume of Gas Equivalents	
2,234 MW Nuclear Output at 92% capacity factor	18,004.3 GWH
Equivalence in Millions of Dekatherms	127,900,000 DTs
Equivalence in Residential Customers	2,804,688 residences
Number of SCE&G Residential Customers 2007	273,000 residences
2007 Total SCE&G Gas LDC Sales	40,700,000 DTs

The following table compares the amount of annual emissions generated by the two nuclear plants compared to a similar amount of energy generated by gas.

Emissions	2,234 MWs of Nuclear	2,234 MWs of Natural Gas	
		Annually	60 Year Life
CO_2	0	8,500,000 tons	510,000,000 tons
SO_X	0	55 tons	3,300 tons
NO_X	0	1,350 tons	81,000 tons

Regarding Renewable Power

SCE&G considers non-traditional sources of generation in its planning. In fact it depends on 90 MWs of co-generation capacity in its Cogen South facility. This facility co-fires coal and the biomass waste from a paper manufacturing plant. Some proposed bills in Congress have defined renewable as: geothermal, hydro, wind, solar and biomass. Unfortunately there are no sites for geothermal generation available in South Carolina. SCE&G generates about 5% of its energy from hydro power. The Company has invested in its existing hydro sites and increased hydro output as a result. The Company will continue to pursue other such economic opportunities but no sites have been identified for a new hydro facility. Both wind and solar have been considered but because of the high capital costs and the limited energy production caused by low wind speeds and insufficient solar radiation, these generation sources are not economical within the SCE&G service territory with current and foreseeable technologies. SCE&G has also evaluated new potential biomass applications in recent years, but none have proven economically feasible and operationally practical yet, but SCE&G continues to examine proposals and opportunities as they are identified.

As potentially valuable as renewable power may be in the future in South Carolina, it is important to keep in mind that it is not likely in the near future to approximate the amount of clean energy that can be produced by the two nuclear units described in this Application.

The following table provides some indication in terms of area of how much solar or wind power would be required.

Renewable Power: To Get Equivalent Energy As 2,234 MW Nuclear		
	Area	Description of Need to Generate 18,004 Million KWH
Solar	61,656 acres	10,276 MWs of solar panels using 6 acres of land per MW generating at a 20% capacity factor.
Wind	120,192 acres	2,284 off-shore wind turbines rated at 3 MWs each generating at a 30% capacity factor.

Since there are about 640 acres in a square mile, the area of 61,656 acres for solar is also 96.3 square miles and the area of 120,192 acres for wind is also 187.8 square miles. Furthermore, the required wind turbines must be given a one-quarter mile spacing for proper operation and so if placed off-shore would cover the length of the South Carolina coast line with three rows of turbines.

These proposed nuclear units also displace a significant amount of CO_2 that might otherwise have been emitted by a fossil plant. The following table shows how many trees would need to be planted to offset an equivalent amount of CO_2 on an annual basis.

Carbon Offsets: Using Equivalent Energy As 2,234 MW Nuclear			
Generation Source	CO_2 Emitted in millions of Tons	Number of Trees in millions	Land Area in Acres
Coal	19.1	795	1,766,000
Gas	8.5	350	778,000
Note: A mature tree consumes 48 lbs of CO_2/year and about 450 trees require one acre of land.			

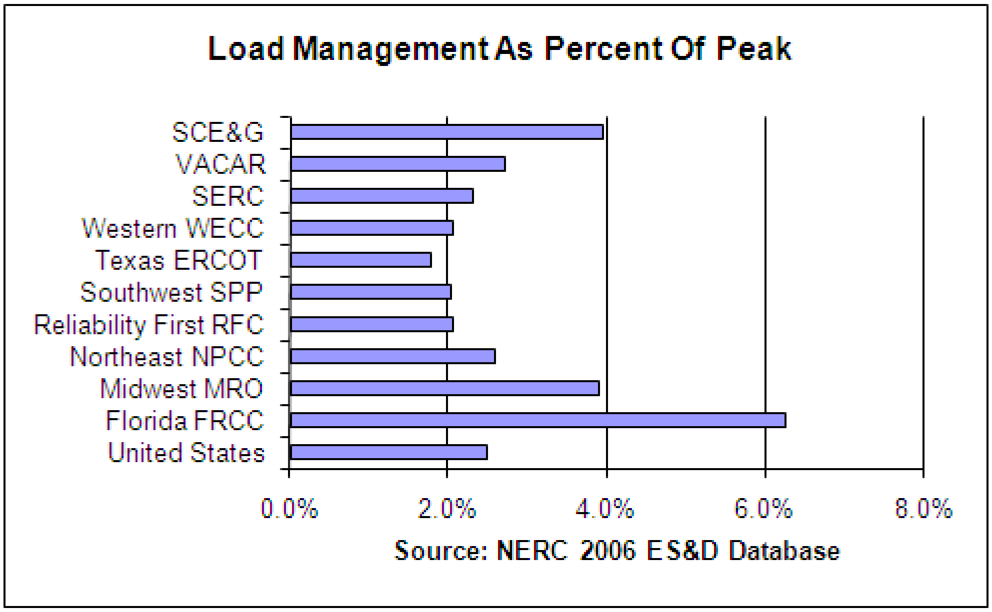
Regarding Demand Side Management
SCE&G has had a demand side management program in place for many years and has reported on it in its integrated resource plans which are currently filed annually. Below is an outline of these DSM programs.

1. Customer Information Programs
    a. Annual Energy Campaign
    b. Internet-Based Information and Use Analysis
2. Energy Conservation Programs
    a. Value Visit Program
    b. Energy Saver Rate
    c. Seasonal Rates
3. Load Management Programs
    a. Standby Generator Program
    b. Interruptible Load Program
    c. Real Time Pricing (RTP) Rate
    d. Time of Use (TOU) Rates

A few measures of success of these programs are the following:

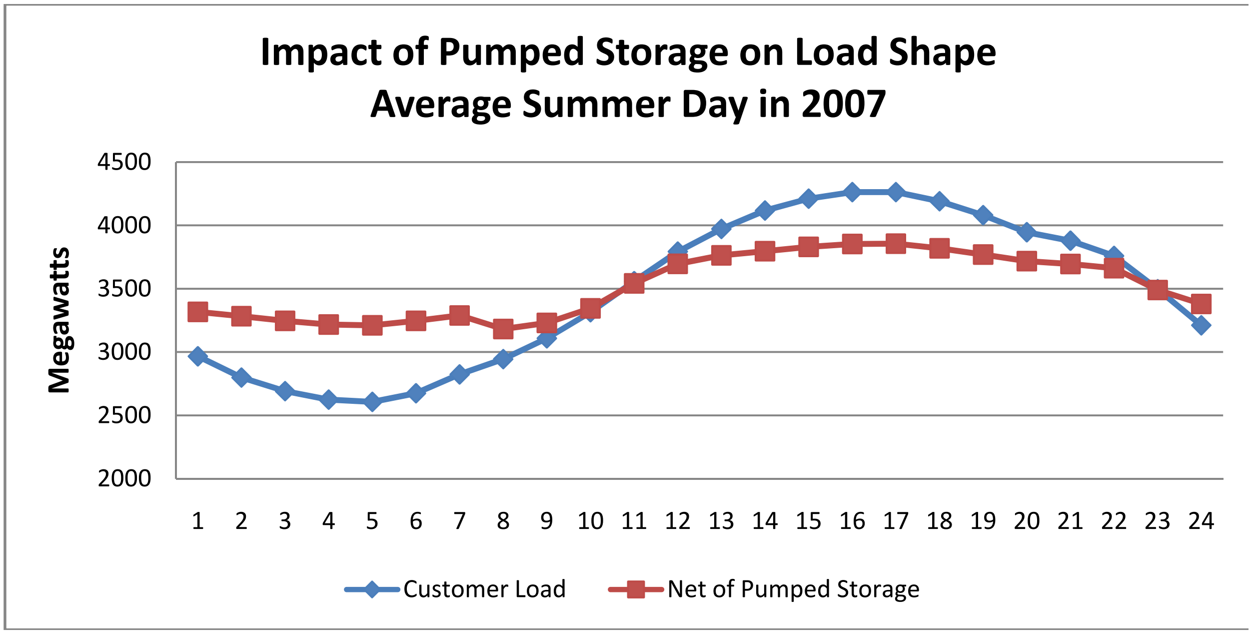
- Almost 200,000 customers are registered for internet access;
- Over 50,000 customers are on the Conservation Rate; and
- 20% of commercial sales are served on TOU or RTP rates.

Through our load management program, also known as demand response, we are able to avoid 234 MWs of capacity in the form of interruptible load and standby generation. To put this in perspective the following graph compares the magnitude of SCE&G's demand response program to other areas of the country.



As can be seen in the graph only Florida with its winter morning spikes in load has more demand side load management.

One other advantage that SCE&G has over many other utilities is its pumped storage facility in Fairfield County. The following graph shows the impact that this unit had on the system load shape during the summer of 2007.

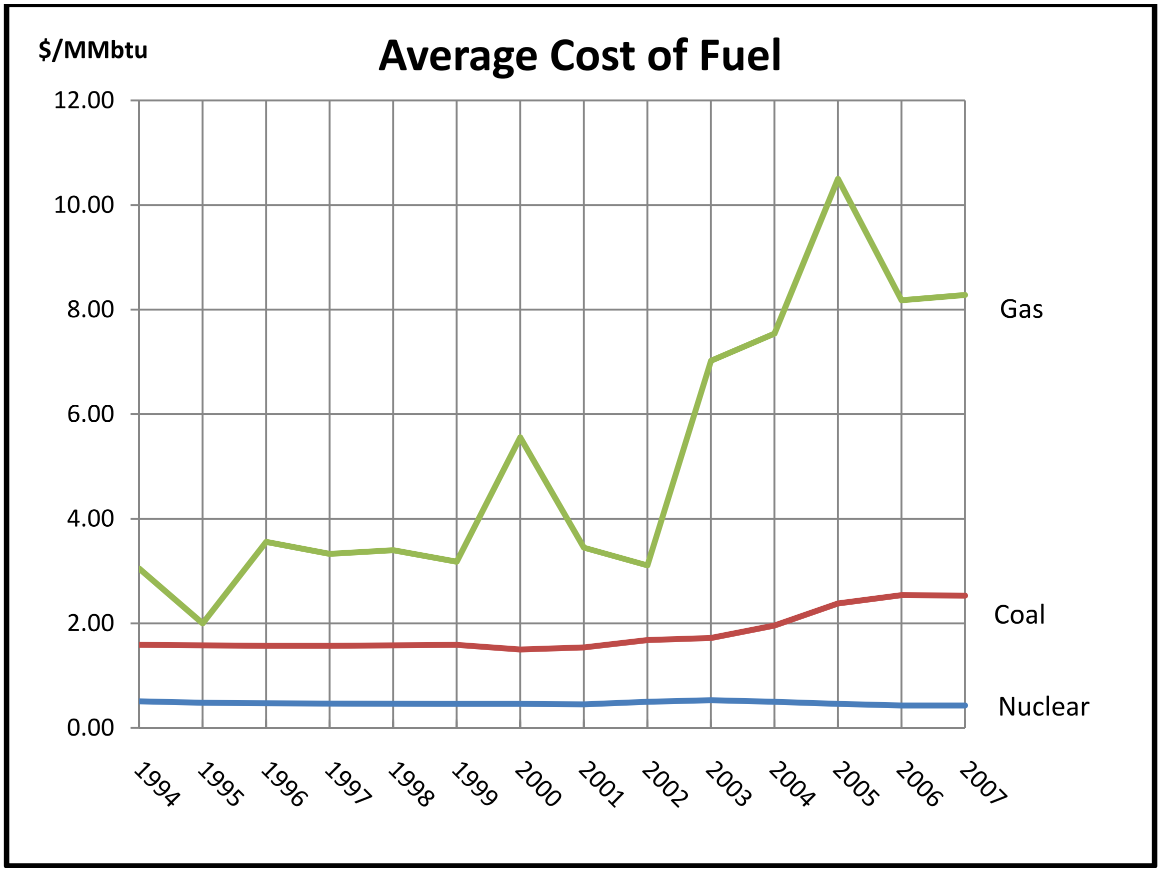


In effect the Fairfield Pumped Storage Plant shaved about 400MWs of load from the daily peak times of 2:00pm through 6:00pm and moved almost 4% of customer's daily energy needs to the off peak. Clearly it would take a demand-side program of significant size to produce an equivalent peak load shifting effect on the system.

In addition to the above the company is taking steps to revise and expand its collection of DSM programs. A new department has been created within the Company this year with the mission of developing the best portfolio of DSM programs to serve SCE&G's customers. As indicated above, DSM can play a useful and important role in reducing the demand for electricity on SCE&G's system. Reasonably anticipated gains from DSM programs, while quite beneficial, would not displace the need for the new nuclear units.

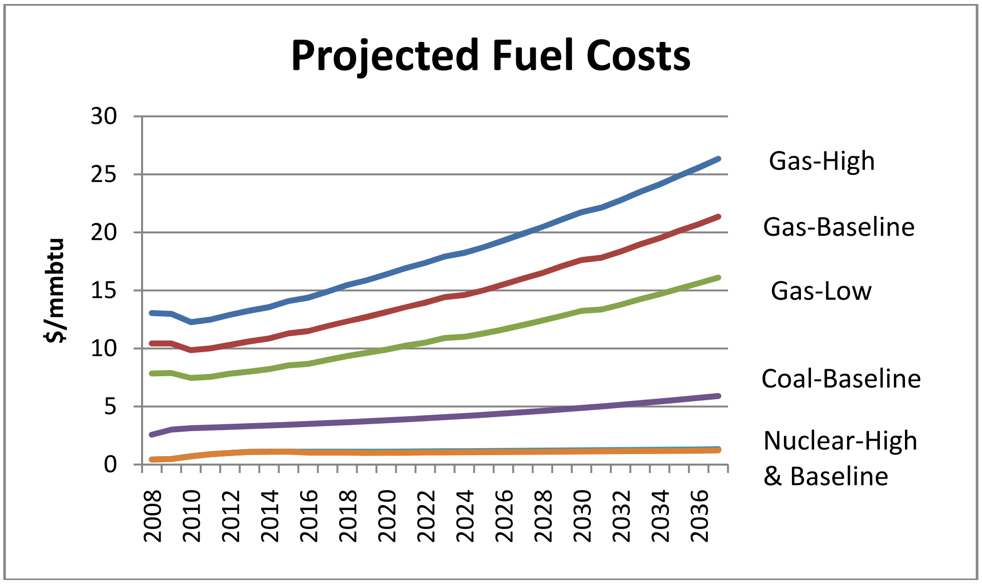
Regarding the Cost of Fuel

A significant advantage of nuclear power over gas in particular is the low cost and stability of the fuel price. The following graph shows SCE&G's experience with the cost of natural gas, coal and nuclear power over the last 15 years. The volatility of natural gas prices is shown in stark contrast to the relative stability of both coal and nuclear costs. The significant increase seen in natural gas prices especially in the last 5 years provides a strong argument for more fuel diversity away from reliance on natural gas generation.



Sources: Annual 10-K reports sent to Securities and Exchange Commission (nuclear, coal, gas:2001-2007)and FERC Form 1 annual reports (gas:1994-2000).

There were three scenarios of projected natural gas prices and two scenarios of nuclear prices constructed for the economic analysis that is discussed in the next section. The high and low gas price forecast is plus and minus 25% respectively of the baseline gas price forecast. The high nuclear price forecast is about 10% higher than the baseline forecast. Both nuclear price forecasts are purchased from the UX Consulting Company.



The high and baseline nuclear price forecasts are almost indistinguishable in the graph because of the scale required to include the higher gas prices even though the high nuclear price is almost 10% greater than the baseline price.

Regarding the Economic Analysis
Three expansion plan strategies are compared in an economic analysis using SCE&G's baseline assumptions. These strategies are: the nuclear strategy, the gas strategy and the coal strategy. Both the nuclear and the coal strategies include gas capacity in the form of combustion turbine peaking units (CTs). The following table summarizes each planning strategy.

Strategy	Description
Nuclear Strategy	Add two nuclear units at 614MWs each in 2016 and 2019. Add 24 CTs at 93MWs each along with purchases throughout planning horizon as needed to maintain a 12% minimum reserve margin.
Gas Strategy	Add three combined cycle natural gas units at 520MWs each in 2016, 2024 and 2031. Add 20 CTs at 93MWs each along with purchases throughout planning horizon as needed to maintain a 12% minimum reserve margin.
Coal Strategy	Add two coal units at 600MWs each in 2016 and 2019. Add 24 CTs at 93MWs each along with purchases throughout planning horizon as needed to maintain a 12% minimum reserve margin.

The following table shows the results of an economic analysis using SCE&G's baseline assumptions.

Levelized Present Value of Comparative Revenue Requirements ($Million Per Year) – Shown as Change from the Nuclear Strategy	CO_2 at $15	CO_2 at $30	High Natural Gas Prices
1) Nuclear Strategy	-	-	-
2) Gas Strategy	15.1	125.2	68.5
3) Coal Strategy	94.9	267.5	99.0
Note: Revenue includes production costs for all plants and the capital costs of all new plants.			

The nuclear strategy is seen to be the lowest cost option for SCE&G's customers over the long run. Cost here is measured in terms of the impact on SCE&G's customers' bills and is quantified in the table as the levelized present value of comparative revenue requirements. Comparative revenue requirements refer to all fixed and variable production costs from all of the power plants plus the capital costs from all of the incremental power plants. Each of the three strategies includes enough capacity to meet a minimum reserve margin of 12%. For example, the "nuclear" strategy includes adding two nuclear units in 2016 and 2019 as well as sufficient purchases and peaking turbines to maintain the minimum reserve margin throughout the planning horizon of 40 years. Referring to this table, it can be seen that the gas strategy would cost SCE&G's customers $15.1 million per year more than the nuclear strategy if CO_2 costs $15 per ton in 2012 and escalates at 7% per year. With CO_2 at $30 per ton, the cost advantage of nuclear would be $125.2 million per year. A higher natural gas price with CO_2 at $15 per ton shows a nuclear cost advantage of $68.5 million per year.

The following table shows the results from scenarios in which assumptions unfavorable to the nuclear strategy were made. For example, if uranium fuel prices follow a high track, the nuclear strategy still has a positive advantage over the gas strategy by $13.2 million per year but if natural gas prices follow a low track, then the gas strategy has the advantage over nuclear by $44.9 million per year. Additionally, if there is no legislation imposing additional costs on CO_2 emissions, the gas strategy has an $86.5 million advantage over nuclear. However while higher uranium prices are possible, they are not expected. In addition, it does not seem reasonable at this point to expect low gas prices or no CO_2 legislation.

Levelized Present Value of Comparative Revenue Requirements ($Million) – Shown as Change from the Nuclear Strategy	High Uranium Prices	Low Gas Prices	CO_2 at $0
1) Nuclear Strategy	-	-	-
2) Gas Strategy	13.2	-44.9	-86.5
3) Coal Strategy	87.5	90.1	-82.7
Note: Revenue includes production costs for all plants and the capital costs of all new plants.			

As discussed earlier some of our existing coal plants are likely to be retired during the 40-year planning horizon. By adding the nuclear facilities the Company will be in a much better position to protect our customers from high fuel prices. The table below compares the impact of three possible coal retirement scenarios. The "High Forced Outage Rate" scenario assumes that SCE&G continues to operate all its coal plants no matter the age but they become more unreliable with time. The "Retire Small Coal Plants" scenario envisions the need for more environmental investment at each plant, such as, the need to add carbon capture. This type investment is not likely to be economical at smaller coal plants. Finally, the "Retire All Coal When 60 Years Old" scenario is self-explanatory. All three scenarios represent future possibilities. As shown in the table, SCE&G is better able to protect its customers under these scenarios if it pursues the Nuclear Strategy.

Levelized Present Value of Comparative Revenue Requirements ($Million) – Shown as Change from the Nuclear Strategy	High Forced Outage Rate	Retire Small Coal Plants	Retire All Coal When 60 Years Old
1) Nuclear Strategy	-	-	-
2) Gas Strategy	44.9	75.7	68.7
Note: Revenue includes production costs for all plants and the capital costs of all new plants.			

While no one knows with certainty what a CO_2 credit may cost, the following table presents some points of reference.

$ per Ton of CO_2	Description
$47	Price of carbon futures contract for December 2012 on the Inter-Continental Exchange: 27.75 Euros per metric ton @1.5607 exchange rate (4/25/2008) converted to $ per short ton.
$55	Cost to capture and sequester CO_2. Estimate from a U.S. Department of Energy website http://fossil.energy.gov/sequestration/capture/index.html
$94	Price needed for gas generation at $73 per MWH to displace coal generation at $26 per MWH using variable production costs.

The table below shows the sensitivity of the economic results to the price of a CO_2 credit. For each combination of escalation rate and CO_2 price in 2012, the table shows the approximate difference in levelized revenue requirements between the nuclear strategy and the gas strategy. For example, if the CO_2 price in 2012 is $20 and escalates at 5% per year, then the nuclear strategy would save SCE&G's customers about $19 million per year on a levelized basis. On the other hand if the CO_2 price were only $5 escalating at 2%, then the nuclear strategy would cost about $71 million more per year than the gas strategy. The shaded area highlights the combinations of CO_2 price and escalation which result in the gas strategy being more economical than the nuclear strategy.

Change in Levelized Rev. Req.: Gas Strategy Minus Nuclear Strategy
Positive Entries Represent Nuclear Advantage in Millions of Dollars

CO_2 Price / Escalation	$0	$5	$10	$15	$20	$25	$30	$35	$40	$45	$50
0%	-87	-75	-63	-51	-40	-28	-16	-5	7	19	31
2%	-87	-71	-55	-39	-23	-7	9	25	41	57	73
4%	-87	-64	-42	-20	2	24	47	69	91	113	135
5%	-87	-60	-34	-7	19	45	72	98	124	151	177
6%	-87	-55	-24	8	39	71	102	134	165	197	228
8%	-87	-41	5	50	96	141	187	233	278	324	369
10%	-87	-19	48	116	183	250	318	385	453	520	587

In Summary
Schedule H has shown that:

- These nuclear facilities are the most economical form of generation to add under reasonable assumptions about the future.
- These nuclear facilities meet the Company's need for more base load capacity.
- These nuclear facilities are non-emitting resources and therefore serve to protect the environment while at the same time mitigating exposure to the cost of complying with future environmental regulations.
- These nuclear facilities support the need for fuel diversity in SCE&G's capacity mix.
- Renewable power, increased demand side management (DSM) and potential energy efficiency gains are not capable of replacing the need for more base load generation; however, they could fit nicely into the expansion plan by displacing some of the purchased power currently shown in the plan.

Based on consideration of these factors, SCE&G has determined that constructing the nuclear facilities is the most reasonable and prudent response to its need for future base-load capacity to serve its customers and the people of South Carolina.

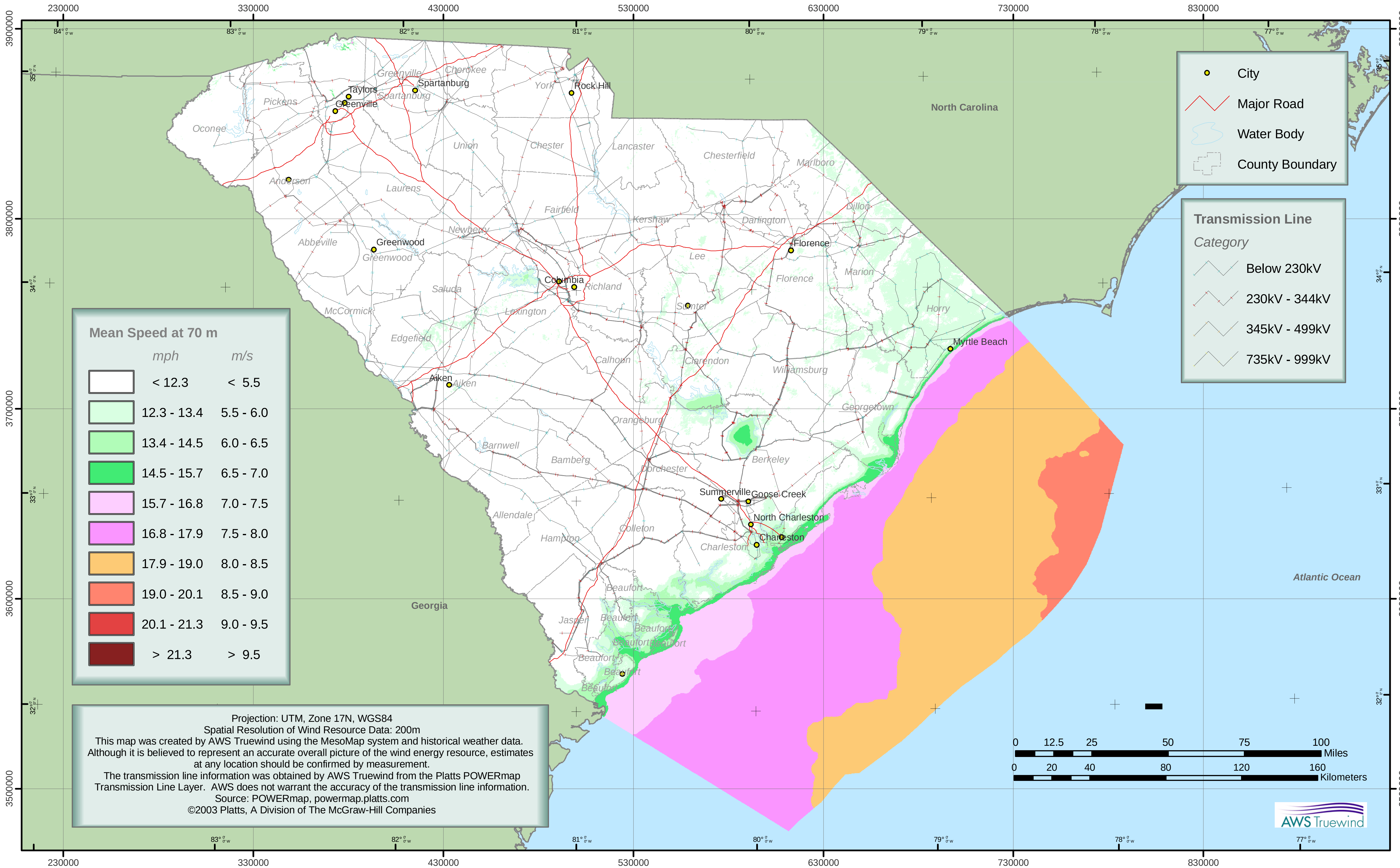
SCE&G Summer Peak Demands (MW)

Year	Retail	Wholesale	Gross Territorial Peak	Projected DSM	Net Territorial Peak	NCEMC	Total Firm Peak
1993	3347	210	3557		3557		3557
1994	3178	188	3366		3366		3366
1995	3473	210	3683		3683		3683
1996	3506	192	3698		3698		3698
1997	3510	224	3734		3734		3734
1998	3700	235	3935		3935		3935
1999	3943	215	4158		4158		4158
2000	3967	244	4211		4211		4211
2001	3986	210	4196		4196		4196
2002	4169	302	4471		4471		4471
2003	4068	294	4362		4362		4362
2004	4337	302	4639		4639	350	4989
2005	4565	326	4891		4891	350	5241
2006	4514	295	4809		4809	350	5159
2007	4696	302	4998		4998	250	5248
2008	4845	321	5165	-234	4931	250	5181
2009	4973	108	5082	-209	4873	250	5123
2010	5101	39	5140	-209	4931	250	5181
2011	5216	40	5256	-209	5047	250	5297
2012	5333	41	5375	-209	5166	250	5416
2013	5428	42	5471	-209	5262		5262
2014	5532	44	5576	-209	5367		5367
2015	5636	45	5681	-209	5472		5472
2016	5749	42	5791	-209	5582		5582
2017	5863	43	5906	-209	5697		5697
2018	5975	45	6020	-209	5811		5811
2019	6087	47	6133	-209	5924		5924
2020	6198	48	6246	-209	6037		6037
2021	6306	50	6355	-209	6146		6146
2022	6415	51	6467	-209	6258		6258

SCE&G Territorial Sales (GWH)

Year	Retail	Adjustment	Adjusted Retail	Wholesale	Total Territorial
1993	15,883	.	15,883	1,006	16,889
1994	15,816	.	15,816	1,024	16,840
1995	16,522	.	16,522	1,063	17,585
1996	16,989	.	16,989	1,023	18,012
1997	16,909	.	16,909	1,060	17,969
1998	18,583	.	18,583	1,125	19,709
1999	18,879	.	18,879	1,139	20,018
2000	20,049	.	20,049	1,204	21,253
2001	19,834	.	19,834	1,114	20,948
2002	20,827	.	20,827	1,448	22,275
2003	20,612	.	20,612	1,432	22,044
2004	21,711	.	21,711	1,521	23,232
2005	21,834	.	21,834	1,485	23,320
2006	21,732	.	21,732	1,486	23,217
2007	22,153	.	22,153	1,509	23,661
2008	22,764	0	22,764	1,522	24,286
2009	23,300	0	23,300	813	24,113
2010	23,994	36	23,958	175	24,133
2011	24,549	72	24,476	181	24,657
2012	25,136	936	24,200	186	24,386
2013	25,604	1,122	24,482	191	24,673
2014	26,100	1,316	24,784	197	24,981
2015	26,610	1,342	25,268	203	25,471
2016	27,147	1,369	25,778	210	25,987
2017	27,695	1,397	26,298	216	26,514
2018	28,247	1,425	26,822	223	27,046
2019	28,809	1,453	27,356	231	27,586
2020	29,351	1,577	27,774	238	28,011
2021	29,889	1,606	28,283	245	28,528
2022	30,448	1,635	28,814	252	29,066

Mean Annual Wind Speed of South Carolina at 70 Meters



DIRECT TESTIMONY

OF

JOSEPH M. LYNCH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2008-196-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION WITH SOUTH CAROLINA ELECTRIC & GAS COMPANY ("SCE&G" OR "COMPANY").

A. My name is Joseph M. Lynch and my business address is 1426 Main Street, Columbia, South Carolina. My current position with the Company is Manager of Resource Planning.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from St. Francis College in Brooklyn, New York with a Bachelor of Science degree in mathematics. From the University of South Carolina, I received a Master of Arts degree in mathematics, an MBA and a Ph.D. in management science and finance. I was employed by SCE&G as a Senior Budget Analyst in 1977 to develop econometric models to forecast electric sales and revenue. In 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and, in 1991, I was promoted to my current position of Manager of Resource Planning.

Q. WHAT ARE YOUR CURRENT DUTIES AS MANAGER OF RESOURCE PLANNING?

A. As Manager of Resource Planning I am responsible for producing SCE&G's forecast of energy, peak demand and revenue; for developing the Company's generation expansion plans; and for overseeing the Company's load research program.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the Company's projected load growth over the next fifteen years and to sponsor and explain the studies conducted by SCE&G that establish the need for additional base load generation in the 2016 time period. I further discuss SCE&G's analysis of the relative economics and feasibility of nuclear and non-nuclear generation and why nuclear is the preferable generation option at this time.

I will testify concerning the Company's analysis of the need for capacity and the contribution that the proposed facilities will make to the economy and reliability of SCE&G's system which are included as Exhibits G and H to the

Combined Application in this proceeding. I have included copies of these documents as exhibits to my testimony which are identified as follows:

Exhibit G (Exhibit No. ___ (JML-1)), *Forecast Need for Electric and Fuel Type.*

Exhibit H (Exhibit No. ___ (JML-2)), *Contribution to System Efficiency and Fuel Type.*

I have also included as exhibits to my testimony copies of three additional documents which are as follows:

Exhibit No. ___ (JML-3), *SCE&G Summer Peak Demands (MW).*

Exhibit No. ___ (JML-4), *SCE&G Territorial Sales (GWH).*

Exhibit No. ___ (JML-5), *Mean Annual Wind Speed of South Carolina at 70 Meters.*

Q. HAS SCE&G CONDUCTED ANY STUDIES PROJECTING ITS ENERGY AND PEAK DEMAND GROWTH OVER THE NEXT FIFTEEN YEARS?

A. Yes, every year in accordance with S.C. Code Ann. § 58-37-40 and Commission Order No. 98-502, SCE&G files an Integrated Resource Plan ("IRP") for meeting the future energy needs of its customers. The most recent IRP demonstrating these forecasts over the next fifteen years, 2008 through 2022, was filed with the Commission on February 28, 2007, in Docket No. 2006-103-E. Subsequently, the Company revised its IRP by filing a revised plan on May 28, 2008.

Q. BASED ON THESE STUDIES, WHAT PEAK DEMAND GROWTH DOES SCE&G PROJECT FOR THE NEXT FIFTEEN YEARS?

A. Over the past fifteen years, SCE&G's retail portion of its peak demand has grown approximately 2.4%, or about 96.4 megawatts ("MW"), per year. SCE&G currently anticipates that the future growth on its retail peak demand will be comparable to its historical experience and will grow at approximately 2.0%, or 112.1 MW, per year over the next fifteen years. With respect to total territorial peak load, the Company has historically experienced a growth rate of 2.5% per year. However, SCE&G projects that its firm territorial summer peak demand and winter peak demand will grow only 1.7% per year. The projected reduction in the level of growth is the result of the forthcoming loss of the City of Orangeburg as a customer in May 2009 and the expected loss of two other wholesale customers before 2010. As shown in **Exhibit No. __ (JML-3)**, the loss of these customers will reduce the Company's wholesale load from 302 MWs in 2007 to 39 MWs in 2010.

Q. DID SCE&G TAKE THESE WHOLESALE CONTRACTS INTO CONSIDERATION WHEN IT DETERMINED ITS CAPACITY NEEDS?

A. Yes. When SCE&G signed contracts with these entities a few years ago, SCE&G anticipated that it would need additional capacity in 2009. The Company, therefore, limited the term of the contracts so that they would expire during the 2009-2010 period thereby providing greater flexibility in its resource planning.

Q. HAS SCE&G CONDUCTED ANY SIMILAR STUDIES WITH RESPECT TO ITS PROJECTED ENERGY GROWTH?

A. The Company originally projected retail energy sales to grow at a rate of 2.1% per year over the next fifteen years compared to a historical growth of 2.4% per year over the prior fifteen years. A portion of this lower growth can be attributed to the mandated increase in efficiency for space conditioning units. The mandated minimal seasonal energy efficiency rating ("SEER") was recently increased from 10 to 13, a 30% increase in efficiency. The Company's forecast reflects efficiency increases anticipated to result from the passage of legislation mandating minimum SEER ratings. Subsequently, in December 2007, the United States Congress passed the Energy Security and Independence Act of 2007 ("ESAI"). This legislation concerns the overall energy policy of the United States and, among other things, will have a significant impact on energy growth through its efficiency standard on residential and commercial light bulbs. Although the impact of this law is not certain, SCE&G has made a significant reduction to its forecasted retail sales to reflect the mandated increases in the energy efficiency of light bulbs, including a doubling of current energy efficiency by 2020. After adjusting for the impact of this law, the Company's projected growth in retail sales is 1.7%

per year. Unlike retail sales, territorial sales include sales to full requirements wholesale customers. In comparison to total territorial sales growth, the Company is expected to experience a more marked drop in growth due to the expected loss of SCE&G's three largest wholesale customers. Based on these factors and as more fully described in **Exhibit No. ___ (JML-4)**, the Company currently projects that over the next fifteen years, its territorial energy sales will grow approximately 1.3% per year.

Q. PLEASE EXPLAIN HOW THE ESAI LEGISLATION IMPACTS THE COMPANY'S ENERGY SALES.

A. The ESAI legislation sets forth many requirements which will likely have an impact on energy sales nationwide. The most significant provision of the legislation with respect to energy consumption mandates an increase in the efficiency of light bulbs which effectively prohibits the continued manufacturing of most of the incandescent light bulbs produced today. For example, by 2012, a 100 watt incandescent bulb produced today must produce the same amount of lumens while consuming only 72 watts, or increase its efficiency by 28%. By 2013, 75 watt bulbs must also be 28% more efficient producing the same amount of lumens while consuming only 54 watts. A 60 watt bulb must meet the same efficiency standards by the year 2014. By contrast, compact fluorescent bulbs ("CFLs") produced today are about 73%

more efficient than incandescent bulbs and already meet the efficiency requirements of the law.

On average, approximately 15% of the energy consumed by a residential customer is for home lighting. A 73% reduction in lighting energy through the use of CFLs would correlate to approximately an 11% reduction (73% x 15%) in total residential electric consumption. Approximately 24.6% of the energy consumed by the average commercial customer is used for lighting; however, because commercial facilities are already larger users of fluorescent bulbs, the Company projects that ESAI will only increase commercial customer efficiency by 8%. Thus, for the average commercial customer SCE&G projects that total consumption will decrease approximately 2% (24.6% x 8%).

Q. TAKING THESE ISSUES INTO ACCOUNT, WHAT IS THE PROJECTED LOAD THAT SCE&G WILL BE REQUIRED TO SERVE IN 2016?

A. As shown on **Exhibit No. ___ (JML-3)**, the Company projects that its firm summer peak demand in 2016 will be 5,582 MW.

Q. WHAT IS THE CURRENT SUPPLY CAPACITY OF SCE&G?

A. As shown in **Exhibit G (Exhibit No. ___ (JML-1))**, Page 2 of 3, SCE&G's total supply resource capacity is currently 5,745 MW.

Q. WILL THIS AMOUNT OF GENERATING CAPACITY MEET THE NEEDS OF SCE&G'S CUSTOMERS AND SYSTEM THROUGH 2016?

A. No, it will not. **Exhibit G (Exhibit No. ___ (JML-1))**, Page 1 of 3, contains the Company's peak demand forecast and the projected supply shortfall. Without additional capacity either through purchase or self-built generation facilities, SCE&G's reserve margin will decline below the Company's minimum target range of twelve percent (12%) and fall to an unacceptable two percent (2%) by 2016.

Q. WHAT IS SCE&G'S PLANNING RESERVE MARGIN TARGET AND HOW DOES IT AFFECT THE NEED FOR CAPACITY?

A. The Company provides for the reliability of its electric service by maintaining an adequate reserve margin of supply capacity. SCE&G has historically maintained a planning reserve margin target of 12-18% of firm peak demand. However, the Company has exceeded this range in some periods when large new generation has been added to its system. This range of reserves allows SCE&G to have adequate daily operating reserves and to have reserves to cover two primary sources of risk: supply side risk and demand side risk. Supply side risk refers to the risk of some generating capacity being down-rated or forced offline. Demand side risk refers to the risk of experiencing higher loads than expected because of abnormal weather or forecast error. As a member of the Virginia-Carolina ("VACAR") subregion of the Southeast

Reliability Council, SCE&G's level of daily operating reserves is dictated by operating agreements with other VACAR member companies. VACAR has set the region's reserve needs at 150% of the largest unit in the region. SCE&G's pro rata share of this capacity for 2008 is approximately 200 MW. Taking these risks and needs into account, SCE&G must maintain a minimum reserve of 12% of its firm peak demand to reliably serve its customers.

Q. WHAT TYPES OF GENERATION HAS THE COMPANY CONSIDERED TO MEET THESE NEEDS?

A. The Company primarily focused its analysis on seven types of generation facilities: solar, wind, landfill gas, biomass, natural gas, coal and nuclear.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S CONSIDERATION OF SOLAR POWER?

A. The Company's analysis of solar power concluded that the necessary facilities are simply too expensive to construct. Photovoltaic systems cost about $4,000-$6,000 per KW and a solar thermal power plant would cost about $3,600 per KW. Additionally, in South Carolina, solar power will only achieve a low-capacity factor of approximately 15-20%. While there is no fuel cost involved with solar energy, the amount of energy produced by the plant would not be sufficient to overcome the very high capital costs.

In addition to these significant limitations, solar power is not dispatchable. The energy output of the plant is wholly dependent upon energy from the sun and the hourly profile of the sun's energy throughout the day is not a perfect match to the hourly profile of SCE&G's load. In particular the sun shines strongest in the summer around noon and 1pm. But in the summer SCE&G always peaks after 2pm and before 6pm with the peak occurring after 4pm about 60% of the time. After 4pm a solar panel will only generate about 20% of its rated capacity thus significantly impacting the capacity of the plant when it would be needed most.

Q. DOES SCE&G CURRENTLY RECEIVE ANY OF ITS ENERGY SUPPLY FROM SOLAR PANELS ON ITS SYSTEM?

A. The Company is purchasing power from three customers on the system who have installed solar panels. In addition to payments through the Company's small power producers rate, these customers are subsidized by federal and state tax incentives and to some extent by payments from the Palmetto Clean Energy organization.

Q. DOES THE COMPANY CONSIDER WIND POWER TO BE A VIABLE OPTION FOR ELECTRIC GENERATION IN SOUTH CAROLINA?

A. Unfortunately, no. Current wind turbine technology requires average wind speeds of approximately 7.5 meters/second ("m/s") to operate and about

12-14 m/s to reach maximum power output. As demonstrated by **Exhibit No. ___ (JML-5)** which contains a wind speed chart for South Carolina produced for the South Carolina Energy Office by AWS Truewind Company, on-shore wind in the state averages less than 5.5 m/s and does not have sufficient strength to make wind a feasible option.

Q. IF IT IS SO DIFFICULT TO GENERATE ELECTRICITY WITH WIND TURBINES, WHY IS WIND POWER BEING ADDED ELSEWHERE IN THE COUNTRY?

A. Wind power is being added in other regions of the United States primarily because certain states have mandated its installation whether economical or not and secondarily because the wind blows strong enough in some regions to make wind feasible. For example, Texas generates more capacity from wind power than any other state with about 4,300 MWs; however, Texas's wind speeds average around 6.4-8.8 m/s. Similarly, California, which is second to Texas in the amount of wind capacity in the country, has average wind speeds of around 8.0-8.8 m/s.

Q. ARE THERE OTHER DRAWBACKS TO WIND POWER?

A. Like solar power, a wind power plant is not dispatchable nor is its capacity dependable since power can only be produced when the wind is blowing at a sufficient speed – when the wind stops blowing, the generation of power stops. For example, in California on the peak day of July 24, 2006, 2,500 MWs of possible wind capacity was only able to produce 255 MWs of power, or approximately 10% of rated capacity, due to a drop in wind speeds. Also, in Texas on February 26, 2008, the wind abruptly stopped and, just as abruptly, the Electric Reliability Council of Texas ("ERCOT") lost 1,700 MWs of generation. To maintain the transmission grid and serve the load, ERCOT had to scramble to interrupt customers, call on other DSM measures and start backup generators.

Because of these limitations, about 90% of the capacity from a wind farm is typically backed up with some other form of generation such as quick start peaking turbines. Additionally, the lack of dependability of these systems means that only 10% of the capacity of a wind power plant is considered firm capacity. In other words, a 1,000 KW wind farm might require about 900 KWs of gas fired combustion turbine capacity to backstand the wind capacity.

Q. YOU STATED EARLIER THAT SOUTH CAROLINA HAD INSUFFICIENT ON-SHORE WINDS TO MAKE WIND POWER FEASIBLE. DID SCE&G CONSIDER OFF-SHORE WIND POWER?

A. The Company certainly considered this alternative and recognizes that the wind blows more dependably off-shore than on-shore. However, SCE&G does not currently consider off-shore wind power a commercially viable technology because of the uncertainty related not only to the wind characteristics but also to the cost of building and maintaining a power plant off-shore along with the related transmission facilities needed to bring the power back to the Company's system. Moreover, the Company is not aware of any utility that has installed off-shore wind turbines in areas prone to be impacted by hurricanes. Because of so much uncertainty, the considerable cost of this technology and the fact that off-shore wind power is expected to achieve only a 30%-35% capacity factor, the Company believes it prudent to forego this technology for the time being.

Q. WOULD LANDFILL GAS PLANTS BE ECONOMICAL ON THE SCE&G SYSTEM?

A. Based on the Company's estimates of cost, SCE&G expects that landfill gas plants would be economical to employ on its system; however, these facilities are very small, typically producing only about 5 to 10 MWs per plant.

Q. DOES SCE&G EXPECT TO ADD THIS TYPE OF CAPACITY IN THE FUTURE?

A. The Company is certainly looking into this possibility; however, the potential is very limited and many of the best locations in the state have already been captured by Santee Cooper, which currently has 4 sites producing a total of about 25 MWs.

Q. IS THERE ENOUGH CAPACITY FROM LANDFILL GAS IN THE STATE TO AFFECT YOUR NUCLEAR DECISION?

A. No, there is not enough landfill capacity in the state to replace the nuclear capacity that we are planning to add.

Q. IS BIOMASS A REASONABLE ALTERNATIVE FOR GENERATING CAPACITY?

A. The economic feasibility of a biomass facility is very site specific and circumstance specific. Therefore, there may be opportunities for a biomass facility that would be cost-effective on the SCE&G system. In fact, SCE&G operates a 90 MW plant at its Cogen South facility which generates about 50% of its energy from biomass fuel generated by waste from a paper manufacturing facility. However, biomass power is typically not economically competitive with more traditional sources of power. The construction cost of a typical biomass plant averages approximately $2,700 per KW with a heat rate of 13,000 for the typical biomass plant. At this level of cost, biomass is simply not competitive with alternative forms of generation.

Q. IF SCE&G WERE PRESENTED WITH ACCEPTABLE OPPORTUNITIES WHICH WOULD MAKE BIOMASS A FEASIBLE ALTERNATIVE, MIGHT THAT ELIMINATE THE NEED FOR THE PROPOSED NUCLEAR PLANTS?

A. No, not at all. There is simply not enough realistic potential biomass capacity available to eliminate the need for the nuclear plants. In fact, the consultant group La Capra Associates recently performed a feasibility study for Central Electric Cooperative and concluded that biomass generation could realistically produce approximately 491 MWs in South Carolina, consisting of 423 MWs from wood waste and 68 MWs from agricultural by-products. Because SCE&G serves about 27% of the state, the Company estimates that approximately 132 MWs of biomass generation potential exists in its service territory. If SCE&G is able to take advantage of all of this potential, the Company could easily incorporate the 132 MW of power in its resource plan and displace some of the purchased power contracts in the resource plan. The need for the two nuclear units would be unaffected.

Q. ARE THE LA CAPRA STUDY RESULTS REASONABLE?

A. Yes, I believe they are. La Capra Associates is very experienced in these types of studies having conducted their analysis in several states throughout the country, including North Carolina. A group of SCE&G's managers and engineers were able to discuss the study results in depth with the principal investigator for the La Capra study. Further, Clemson University performed a similar potentiality study for biomass which also estimated the realistic biomass potential in South Carolina to be about 400 MWs. These circumstances lead SCE&G to believe that the results and findings of the study are reasonable.

Q. HAS SCE&G TAKEN ANY STEPS IN AN ATTEMPT TO REDUCE DEMAND SUCH THAT ADDITIONAL CAPACITY WOULD NOT BE NECESSARY?

A. Yes. SCE&G, like all utilities, operates a collection of Demand Side Management ("DSM") programs. There are two types of DSM programs. The first type comes under the heading of demand response ("DR") programs which are designed to lower peak demands and move consumption out of peak periods. The second type are energy efficiency ("EE") programs which are designed to lower energy consumption in general and not directly during peak periods.

Q. PLEASE EXPLAIN SCE&G'S DEMAND RESPONSE PROGRAMS.

A. SCE&G has been very successful with its DR programs. Through its interruptible load program and its standby generation program, SCE&G has been able to reduce its firm demand by approximately 4% thereby avoiding the need for more than 200 MWs of peaking capacity in its resource plan. Additionally, SCE&G provides time of use ("TOU") rates to all its customers and Real Time Pricing ("RTP") rates to large customers, both of which offer lower prices during off-peak periods thereby providing the opportunity for customers to save money by moving consumption out of peak periods. Finally, SCE&G derives DSM benefits from its Fairfield Pumped Storage Facility which operates like a giant battery, storing low cost power at night and releasing it during the day. Fairfield can effectively shift up to 576 MWs of peak load to off-peak generation. This benefit is more fully described in **Exhibit H (Exhibit No. ___ (JML-2))**, Page 6 of 11, which shows Fairfield's impact on SCE&G's average weekday load profile.

Q. ARE THERE REASONABLE OPPORTUNITIES FOR SCE&G TO EXPAND ITS DEMAND RESPONSE EFFORTS?

A. Except for a modest increase in the standby generator program designed to bring it to a more significant level for dispatching, the answer is no. SCE&G has effectively reached the maximum limit for useful demand response for several reasons:

1. SCE&G's demand response capacity represents approximately 4% of its firm peak. As shown in **Exhibit H (Exhibit No. ___ (JML-2))**, Page 5 of 11, the average around the country is between 2% and 3%. Florida, which has a response capacity of approximately 6%, is the main exception to this rule because they have a very spiked peak in winter when electric strip space heating and water heaters come on in the morning.

2. SCE&G currently has about 200 MWs of demand response capability. An additional 100 MWs of such capability would fall lower on the Company's load duration curve and would, therefore, have to be operational for two weeks or more. SCE&G believes that this would place a significant strain on participating customers such that they would not be willing to continue participating in the long term.

3. SCE&G attempts to run the system at the low end of its reserve margin range, 12%, in order to keep its rates as low as possible. A DR program is typically less reliable than generating capacity and, with reserves so low, SCE&G would not be comfortable replacing additional capacity with demand response. For example, utilities in Florida are required to maintain a 20% reserve margin. If SCE&G maintained a 20% planning reserve margin, then a 6% level of demand response or more, like in Florida, would be reasonable.

4. Reserve capacity is low not only during hot summer afternoons and cold winter mornings but also during the spring and fall when plants are taken out of service for maintenance. These conditions would place additional stress on customers participating in a new DR program which SCE&G does not think they will bear in the long run.

5. Finally, the Saluda Hydro facility is a valuable part of the Company’s generating fleet providing 206 MWs of capacity to our system. This facility is held in reserve to support system reliability and fulfill the Company’s commitment to VACAR. Similarly, because demand response programs interrupt service to customers, these programs are also used to support system reliability and meet the Company’s commitment to VACAR. When these resources are combined, they represent almost two-thirds of our planning reserves. SCE&G believes that adding significantly more demand response capability would increase this ratio beyond a tolerable limit.

Q. DISCUSS SCE&G’S ENERGY EFFICIENCY PROGRAMS.

A. The Company has two categories of energy efficiency programs: Customer Information Programs and Energy Conservation Programs. The Customer Information Programs include:

- The Annual Energy Campaign: Each year SCE&G takes steps to educate its customers on energy efficiency by distributing brochures and printed materials containing energy tips; bill inserts targeting low income customers; weatherization projects to help low income customers; news releases; direct mailing of our Energy Wise Newsletter; and a significant amount of online literature and home project videos.

- WEB-Based Information and Services Programs: As with the Annual Energy Campaign, this program makes available literature and recommendations but also provides the customer with the ability to analyze individual consumption patterns and the impact weather has on the cost of electricity. Additionally, this program allows customers to perform online home audits.

SCE&G's Energy Conservation Programs include the Value Visit Program which provides expert advice to residential customers considering upgrading their home's energy efficiency. This assistance can be obtained through home visits, telephone conversations or email correspondence. The program also provides financial assistance to help offset the cost of added insulation, storm windows or certain other measures.

Q. HAVE THESE DSM PROGRAMS PROVEN TO BE SUCCESSFUL?

A. Yes they have. We look at the following measures of success:

- The demand response component has reached its useful limit of more than 200 MWs.
- About 174,000 customers are registered for WEB access.
- Almost 97,000 customers accessed the "Energy Analyzer" tool in 2007.

- Over 50,000 residential customers receive service on the Energy Conservation Rate.
- About 20% of commercial consumption is provided under our TOU or RTP rates.

Q. DOES SCE&G PLAN TO EXPAND ITS PORTFOLIO OF PROGRAMS?

A. Yes it does. SCE&G recently took an important step to expand these offerings by establishing a Department for DSM and appointing a Director to manage the revitalization of the Company's energy efficiency efforts. The Company has taken additional steps such as the following:

- The hiring of additional energy auditors to perform residential audits.
- The addition to the Company's website of an online energy audit program to allow customers to analyze various factors which impact their consumption and to explore the benefits of energy efficiency.
- A survey of customers to determine what programs might interest them and which they would support.
- The purchase of a South Carolina Library of DSM Measures containing an estimated KW and KWH impact of various

residential and commercial efficiency measures which will be the building blocks for any energy efficiency programs.

- The retention of a consulting firm with expertise in the area of energy efficiency and in the estimation of its potential on a utility system.

SCE&G plans to use these tools to develop a comprehensive and effective portfolio of energy efficiency options for its customers.

Q. IS IT POSSIBLE THAT YOUR EXPANDED ENERGY EFFICIENCY EFFORTS MIGHT AFFECT SCE&G'S DECISION TO BUILD TWO NUCLEAR PLANTS?

A. No, they would not for many reasons, including the following:

- The impact of the Company's future efforts are not known. For the nuclear facilities to be in service as planned, SCE&G needs to begin the process now to ensure that this capacity is available when needed to reliably serve its current and future electric customers.
- Based on the Company's experience with prior energy efficiency programs such as the Great Appliance Trade-Up Program, the Good Cents Program and Energy Audits, these tools, while helpful, may not be enough to overcome the trend toward more electrification and customer use may continue to increase.

- While energy efficiency programs place downward pressure on customer use, new end uses such as plasma TVs and electronic billboards may overcome these gains.
- Much of the growth in energy results from new customers as opposed to an increase in consumption by existing customers. For example residential consumption increased by 39% over the last 10 years while consumption per customer increased by only 9%. Thus about 75% of the energy growth in the residential sector is the result of customer growth. Similar results hold for the commercial sector.
- If the Company's energy efficiency programs are exceptionally effective and energy demand drops significantly, SCE&G would be able to use the new nuclear capacity to reduce its reliance on fossil fuels by avoiding the use of its peaking facilities and perhaps may be able to retire one or more of its aging coal plants without replacing the base load capacity.

Q. DID THE COMPANY ANALYZE THE REASONABLENESS OF MORE TRADITIONAL GENERATION SOLUTIONS?

A. Since SCE&G's increased DSM efforts and the potential for renewable power will have only a limited impact on the need for capacity, SCE&G considered traditional sources of power such as gas, coal and nuclear. The nuclear strategy centered on adding nuclear plants in 2016 and 2019 and adding purchased power capacity and combustion turbine peaking capacity in various years to maintain a minimum reserve margin of 12%. The coal plan was developed by replacing the two nuclear plants with two coal plants of about the same size. Several gas plans were considered. One involved adding only peaking capacity and the others involved adding one, two or three combined cycle plants along with a mix of purchased power contracts and peaking turbines to maintain minimum reserves. The least cost of these gas plans included three combined cycle units.

Q. WERE YEARS OTHER THAN 2016 AND 2019 CONSIDERED FOR THE NUCLEAR STRATEGY?

A. No. Year 2016 was chosen because it is the earliest that a nuclear plant can be built and become operational. Originally, SCE&G thought that it might be feasible to have a plant in operation by 2015; however, that goal is not likely to be attainable. SCE&G has scheduled construction on the second nuclear plant so as to allow more load growth to occur while not losing the considerable benefit in economies of construction of two plants. Further, because there are only a few companies in the world that are qualified to construct these facilities and many other utilities are currently planning nuclear construction, postponing the construction of the plants beyond this time frame could result in SCE&G losing its current position in the order of construction which could potentially delay the project for several years. This delay would also result in the Company potentially losing the benefit of federal production tax credits and facing higher costs due to rising construction prices.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ECONOMIC ANALYSIS.

A. **Exhibit H (Exhibit No. ___ (JML-2))**, Page 9 of 11 through Page 10 of 11, contains summary results for nine key scenarios developed by SCE&G in considering gas, coal and nuclear generation. The Company calculated the revenue requirements under each scenario for the 40-year planning horizon. Revenue requirements included the total system production costs and the capital costs for all incremental capacity. The only costs SCE&G excluded from these analyses were sunk costs, such as the capital costs of existing generating units, which would be equal under all scenarios. Additionally, the Company calculated the levelized present worth of each annual stream of revenue requirements and determined the difference in levelized present worth between the nuclear strategy and the alternative strategies under each scenario.

For example, the Company initially determined a "base case" scenario which assumed that CO2 emission allowances would be required and would cost $15 per ton in 2012 escalating at 7% per year. As shown in Column 1 of the first table on Page 9 of 11 of **Exhibit H (Exhibit No. ___ (JML-2))**, following the best gas expansion strategy under these circumstances would cost customers on average $15.1 million per year more than the nuclear strategy and the coal strategy would cost $94.9 million more. If CO2 allowances were to cost $30 per ton as assumed in Column 2 of this table, the cost of the gas strategy would exceed the cost of the nuclear strategy by $125.2 million per year and the cost of coal strategy would increase costs by $267.5 million per year. Similarly, Column 3 of this table shows the Company's analysis of higher natural gas prices with the gas strategy increasing costs by $68.5 million and the coal strategy by $99.0 million.

As shown in the second table on Page 9 of 11 of **Exhibit H (Exhibit No. ___ (JML-2))**, SCE&G also performed an analysis which assumed high uranium prices, low gas prices and no CO2 regulation. Even with high uranium prices, the nuclear strategy is still less costly and only under the scenarios of low gas prices or no CO2 regulation would the gas strategy or coal strategy be less expensive for our customers as shown in this table.

Lastly, the scenarios in the first table on Page 10 of 11 of **Exhibit H (Exhibit No. ___ (JML-2))** were studied to show that by adding these nuclear facilities, the Company will be in a much better position to retire some of its aging base load coal plants and to protect our customers from high fuel prices. This table compares the impact of three possible coal retirement scenarios. The "High Forced Outage Rate" scenario in Column 1 assumes that SCE&G will continue to operate all of its coal plants regardless of age; however, these plants will become more unreliable with time. The "Retire Small Coal Plants" scenario in Column 2 envisions the need for more environmental investment at each plant such as the need to add carbon capture equipment. This type of investment is not likely to be economical at smaller coal plants. Finally, the "Retire All Coal When 60 Years Old" scenario in Column 3 is self-explanatory. All three scenarios represent future possibilities. As shown in the table, SCE&G is better able to protect its customers under these scenarios if it pursues the nuclear strategy.

Q. HAS THE COMPANY STUDIED THE POTENTIAL IMPACT OF ITS NEW DSM EFFORTS ON THE NEED FOR THE NUCLEAR FACILITIES?

A. Yes, we have. Company witness David Pickles will show that in warm weather states like South Carolina, active DSM programs average a 0.36% reduction in total system retail energy sales annually. Nationally, Mr. Pickles testifies that active DSM programs experience an average of a little more than 0.5% in annual energy sales reductions.

Based on Mr. Pickles' information, I have sought to measure the potential results of energy sales reductions at these levels on SCE&G's capacity planning and on the decision to construct the new nuclear units. I assumed that DSM programs were formulated and rolled out in 2009, implemented in 2009-2010, and that the full benefit from them was realized in 2011. I recomputed the models based on a 0.5% annual reduction in energy sales growth for new DSM programs for twelve years and a levelized benefit thereafter.

Q. WHAT CONCLUSION DID YOU REACH?

A. Under the 0.5% assumption, the Company found that building new nuclear generation would still be the most economic strategy for meeting customers' needs.

Q. WHAT TOTAL EFFICIENCY REDUCTIONS ARE REQUIRED?

A. As mentioned above, our forecast is already assuming approximately a 5% reduction in retail sales associated with the increased SEER rating for space conditioning and the increased efficiency in lighting in the 2011-2019 time period. Coupling these reductions which are already included in the forecast with an additional reduction in sales of 0.5% annually would result in a total reduction in sales due to efficiency measures that is well outside what I consider to be a reasonable range.

Q. WHY DID THE COMPANY ASSUME THAT CO2 EMISSION ALLOWANCES WOULD COST $15 PER TON AND ESCALATE AT 7% PER YEAR?

A. SCE&G based its estimations on a 7% escalation in cost by assuming a 2% level of inflation plus a 5% adder. SCE&G also assumed an initial CO2 emissions cost of $15 per ton which the Company believes underestimates the realistic emissions cost which will ultimately be mandated. SCE&G believes that when CO2 is regulated, the price of a CO2 allowance will escalate to a high enough level to actually affect a reduction in CO2 emissions. If the cost of CO2 allowances are set too low, there will be an economic incentive to simply pay the penalty and keep emitting CO2. Therefore, the Company believes that the cost estimates set forth in the second table on Page 10 of 11 of **Exhibit H (Exhibit No. ___ (JML-2))** are much more realistic. However, even assuming the improbably low cost of $15 per ton, SCE&G's analysis demonstrates that nuclear generation would be more advantageous. The table on Page 11 of 11 of **Exhibit H (Exhibit No. ___ (JML-2))** shows the approximate impact on the levelized cost of the gas strategy relative to nuclear for various combinations of start cost and escalation.

Q. WHAT WERE SCE&G'S PROJECTIONS FOR NATURAL GAS PRICES?

A. For the commodity portion of gas price which is the majority of the cost, the Company relied on the prices of futures contracts trading on the NYMEX as of April 22, 2007. SCE&G's analysis of commodity prices, which represent the price of gas at the Henry Hub, used the trading price through 2010 and escalated the prices by 2.8%, which is slightly higher than inflation, to estimate the cost beyond 2010. The Company added its transportation costs to derive a delivered price for gas.

Q. COULD THE COMPANY'S PROJECTION OF GAS PRICES BE HIGH?

A. Yes, it could. Natural gas prices are notoriously difficult to predict accurately. Since 1999, when gas prices began increasing more dramatically, they have been growing by almost 15% per year. Although it is difficult to know whether this trend will continue, it certainly highlights the risk to a utility that depends too heavily on gas generation. Nevertheless, basing a forecast on current levels of gas prices as reflected in the NYMEX futures contracts and escalating at a rate a little above inflation is a reasonable and conservative approach to the problem.

Q. HOW DID THE COMPANY PROJECT THE COST OF NUCLEAR FUEL?

A. SCE&G subscribes to the Ux Consulting Company, which analyzes the nuclear fuels market and provides us with long-term projections of costs.

Q. DO YOU CONSIDER THESE PROJECTIONS OF FUEL COSTS TO BE REASONABLE?

A. Yes, I do.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I conclude by saying that:

- The proposed nuclear facilities are the most economical form of generation to add for the Company's system and its customers.
- The nuclear facilities meet the Company's need for additional base load capacity.
- The nuclear facilities are non-emitting resources and therefore serve to protect the environment while at the same time mitigating exposure to the cost of complying with future environmental regulations.
- The nuclear facilities support the need for fuel diversity in SCE&G's capacity mix.
- Renewable power, increased demand side management and potential energy efficiency gains are not capable of replacing the need for more base load generation; however, they could support SCE&G's expansion plan by displacing some of the purchased power currently anticipated as well as reducing our dependence on aging coal plants.

Based on consideration of these factors, SCE&G believes that constructing the nuclear facilities is the most reasonable and prudent response to its need for future base load capacity to serve its customers and the people of South Carolina.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Gas Resource Strategy

September 27, 2012

SCE&G®
A SCANA COMPANY

Introduction

The purpose of this study is to determine if abandoning SCE&G's ongoing nuclear construction program and pursuing a natural gas generation strategy for base load generation needs would benefit retail customers in terms of long-run revenue requirements. This study is prepared in response to testimony filed on September 6, 2012, on behalf of the Sierra Club by Dr. Mark Cooper in Public Service Commission of South Carolina (Commission) Docket No. 2012-203-E. In that testimony, Dr. Cooper rejected an analysis prepared by SCE&G's Resource Planning Department. That analysis was presented to the Commission in the rebuttal testimony of Dr. Joseph Lynch. It demonstrated on a comparative cost basis that the forecasts of reduced future natural gas prices identified by Dr. Cooper were more than fully offset by the reduced cost to complete the Units going forward. Those reduced costs were due both to lower escalation rates since the inception of the project and the effect of funds already committed to the construction. Dr. Cooper does not dispute that the reduced cost to complete the Units is a relevant factor in such an analysis. However, he insists that only a full recalculation of the relative costs of the gas and nuclear strategies can provide an acceptable basis for answering his concerns.

SCE&G does not accept Dr. Cooper's position that a full study is needed and believes that Dr. Lynch's rebuttal testimony fully answers Dr. Cooper's concerns. Nonetheless, in the interest of demonstrating that Dr. Cooper's concerns are without merit, during the week of September 17, 2012, SCE&G's management directed the Resource Planning Department to use current data to prepare generation cost studies comparable to those performed in 2008 that supported the original decision to construct the Units.

SCE&G has undertaken this exercise expressly reaffirming its position that no single analysis of comparative costs underlies its choice of nuclear generation over gas fired generation alternatives. The goal of base load generation planning is to create a diverse and flexible portfolio of generation units that can perform effectively in multiple sets of conditions over 40 years or more. No single study or series of studies is an effective substitute for informed business judgment exercised with this goal in mind.

This study calculates the incremental revenue requirements on a comparative basis for two strategies. The first is the base case which involves completing the two nuclear units (the Units) which are presently under construction and scheduled to go into service in 2017 and 2018. When completed, the Units together will provide SCE&G with 1,229 MW. The second strategy is the natural gas resource strategy in which the Units are cancelled at the effective date of December 31, 2012. The Units are replaced by two combined cycle units rated at 614 MWs each which come into service in 2017 and 2018 also.

The principal components of the study and conclusion are set forth below. The inputs to the study have been updated to reflect the most current values available.

Load Forecast and Resource Plans

To compute the revenue requirements of the two strategies over a 40-year planning horizon, the study relies on the load forecast data that were reported in summary form in SCE&G's 2012 Integrated Resource Plan. These load forecasts are updated versions of those that were used in the 2008 planning studies (the 2008 Studies) on which the original Base Load Review Act (BLRA) order was based. Both the nuclear and gas resource strategies are measured against identical load forecasts.

Appendix 1 shows the forecast and the base case scenario resource plan reported in the IRP. Both the nuclear capacity and the natural gas combined-cycle capacity are shown on the alternative versions of the resource plan as "base load" capacity entered on line 10 in the table shown in Appendix 1. As was the case with the 2008 Studies, the resource plans for each of the two strategies assumed that, after the base load capacity was added, additional simple-cycle natural gas-fired generation was added to meet subsequent load growth. Comparable amounts of simple cycle generation with comparable capital cost and operating costs were added under each strategy.

Abandoning Nuclear Construction

As of December 31, 2012, SCE&G expects to have spent $1.990 billion on construction of the Units. Appendix 2 is taken from SCE&G's petition in Docket No. 2012-203-E and shows the status of construction spending year to year. In addition, as Mr. Byrne testifies in his rebuttal testimony in Docket No. 2012-203-E, if SCE&G were to decide to cancel the nuclear construction project, it would be subject to contractual cancellation charges, site decommissioning and stabilization expenses and other abandonment expenses in addition to the $1.990 billion that would already have been spent. SCE&G's best assessment of the amount of those cancellation expenses would be $998 million for a cancellation effective December 31, 2012. This is the cost on a 100% basis (i.e., including Santee Cooper's 45% share in expenses).

Upon cancellation of the project, SCE&G could scrap, sell or salvage certain materials, equipment and work in progress and could use the proceeds to off-set some part of the abandonment expenses. A large component of the spending to date, however, has been for site work, construction of roads, building and bridges on site, the hiring and training of personnel, design and procurement work, and other activities that do not produce salvageable materials. SCE&G estimates that of the amounts spent to date, the salvage value of materials, equipment and work in progress would be approximately $290 million on a 100% basis. This $290 million would be netted against the gross cancellation cost of $998 million to produce an estimate of the net cancellation cost, not considering the $1.990 billion already spent, of $698 million, again on a 100% basis. SCE&G's customers would be responsible for 55% of this cost or $384 million.

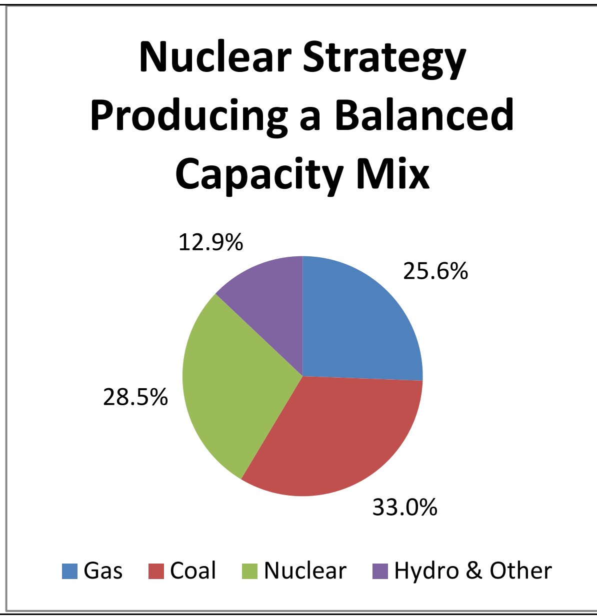
Thus, adding the $1.990 billion spent as of December 31, 2012, and the $384 million in net cancellation costs, the total abandonment cost is estimated to be $2.374 billion.

The model used for comparing the costs of these two strategies computes a levelized cost for capital invested that includes all relevant parameters given the nature of the asset involved. This combination of costs spent to date and additional cost to abandon the project represent a cost that must be borne by the gas resource strategy.

Benefit of a Balanced Capacity Portfolio

A significant advantage of continuing construction of the two nuclear units is that once added to SCE&G's generation fleet, the Units will produce a well balanced capacity portfolio. The following charts show the percent distribution of capacity under a plan of continuing nuclear construction and the alternative of replacing it with natural gas fired capacity.

CHART A



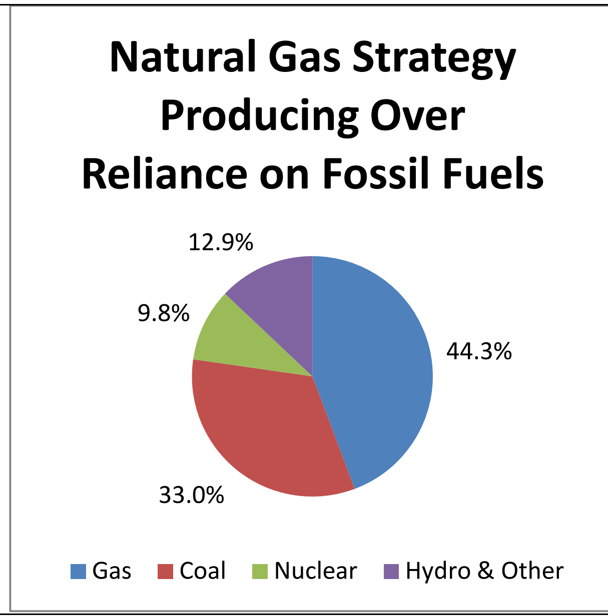


Chart A shows that the Natural Gas Strategy produces a generation system that in 2019 relies on fossil fuels for 77% of its generating capacity. The Nuclear Strategy creates a more balanced portfolio. Such a portfolio better protects customers from unexpectedly high costs in any one fuel source while allowing the utility to take advantage of opportunities in others.

Price of Natural Gas

Chart B shows two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration (EIA) natural gas forecast reported in their 2012 Annual Energy Outlook (AEO). This is the gas price forecast used by Dr. Cooper. The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2015) and then applies an escalation factor projected by the economic forecasting firm IHS Global Insight Inc. to forecast prices beyond three years in the future. This is a methodology that SCE&G has used for a number of years to produce gas forecasts for planning studies. The value of this methodology is that it is simple and objective. However, because all forecasts of future gas prices are subject to error, SCE&G typically tests the results of these studies done using these forecasts through sensitivity analyses that model variations in gas prices.

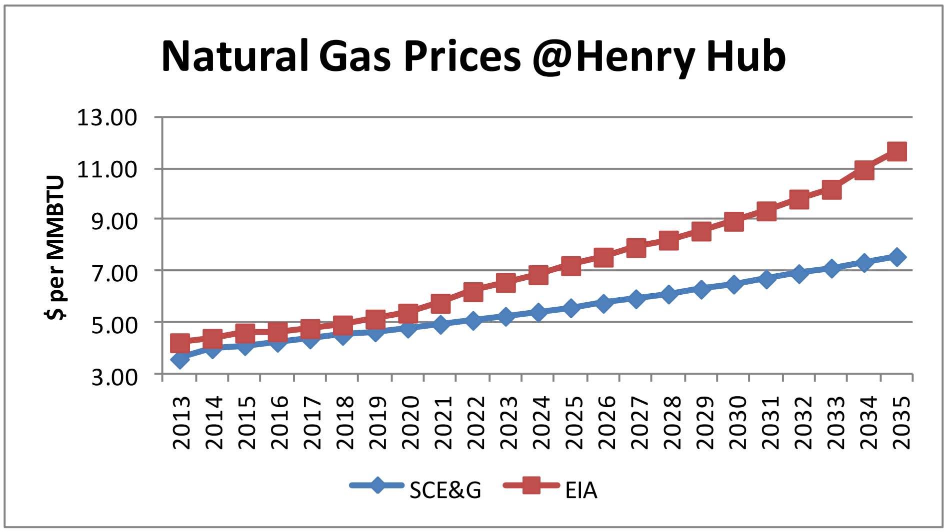
The SCE&G natural gas price forecast is the lowest of the forecasts reported on Charts B and G. It is the forecast used in these studies as the base case value for future gas prices. Charts B and C compare SCE&G baseline natural gas price forecast to the EIA's forecast that was provided in their 2012 Annual Energy Outlook. SCE&G's forecast is lower than the EIA forecast especially in the years beyond 2020.

CHART B

	Natural Gas Price Forecasts @Henry Hub ($ per MMBTU)						
	2013	**2014**	**2015**	**2017**	**2020**	**2030**	**2035**
SCEG Baseline	$3.61	$4.01	$4.13	$4.39	$4.81	$6.51	$7.58
EIA 2012 Forecast	$4.24	$4.41	$4.62	$4.79	$5.39	$8.95	$11.67

Chart C graph compares SCE&G's baseline forecast to that of the EIA.

CHART C



Social Cost of Carbon

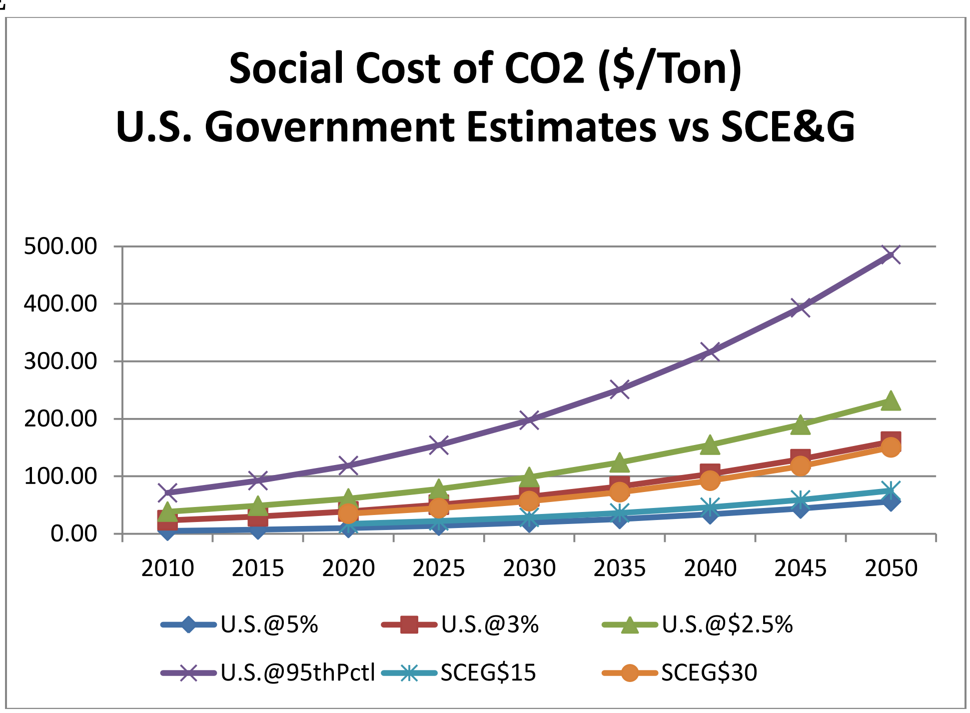
Since there is not a national cap and trade program for CO_2 nor a carbon tax, SCE&G does not face a direct cost related to its CO_2 emissions yet. However, SCE&G feels it would be unreasonable not to incorporate the risk of these direct costs on gas-fired generation in its studies and planning. In 2009, the Obama Administration convened a group of federal agencies to establish a social cost for CO_2 to be used in future rulemaking by federal agencies. In 2010, this interagency committee published its first "social cost of carbon," a monetized value associated with the cost of emitting a ton of CO_2. Chart D shows the Committee's estimates:

CHART D

Table 15A.1.1 Social Cost of CO_2, 2010 - 2050 (in 2007 dollars)				
	Discount Rate			
	5%	3%	2.50%	3%
Year	Average	Average	Average	95th
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50	100
2035	11.2	36	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65	136.2

As the mid-range estimate, the Committee recommended using the "3% Average" column of estimates as a baseline and the other estimates for sensitivity analysis. Since all the estimates are in 2007 dollars, it is necessary to inflate them to a particular year to compare them with SCE&G's study values of $15 and $30 in 2017. Using the 3% Average figure, the estimate of carbon costs by the federal government in 2017 is $33.29. The following graph compares the four government estimates with SCE&G's two estimates.

CHART E



SCE&G's estimates based on a $15 per ton cost are seen to be comparable with the government's lowest estimated social costs of carbon while the cost series based on SCE&G's

$30 estimate falls just below the government's base line projections. In other words, both of SCE&G carbon cost forecasts fall on the low side of the government's range of estimated CO_2 costs.

Capital Costs and Operating Costs of Natural Gas Capacity

The gas resource strategy relies on combined cycle plants for additional base load generation. As mentioned above, both the nuclear and natural gas resource strategies add simple cycle combustion turbines to meet additional capacity needs. Chart F contains the costs and heat rates assumed for these units. These inputs are based on SCE&G's ongoing monitoring of equipment and construction prices and are verified through reviews of published prices, vendor discussions and interaction with peers in resource planning departments at utilities across the country. They reflect current costs to engineer, procure and construct the assets in question including land costs, pipeline connection costs, transmission costs and permitting costs.

CHART F

Gas Technology	Capacity Rating MW	Construction Cost 2012$/KW	Heat Rate BTU/KWH	Fixed O&M Per Year	Variable O&M Per MWH
Simple Cycle	93	$697	9,169	$50,000	$3.95
Combined Cycle	614	$1,000	6,842	$8,000,000	$1.19

Miscellaneous Inputs

In this study, all carrying costs on capital investments are calculated including taxes, depreciation, insurance and cost of capital as applicable to the type of asset in question. Fixed and variable O&M are based on current estimates of turbine maintenance costs for combined cycle units. Nuclear production tax credits have been updated. Nuclear fuel costs are based on current forecasts of uranium prices and prices of new fuel assembly fabrication.

Scenario Analysis

In this study, the nuclear strategy and the natural gas resource strategies were studied under 27 different scenarios: three different natural gas prices, three different costs per ton of CO_2 emitted and three different levels of load on SCE&G's system.

a. Natural Gas Price Scenarios - The natural gas scenarios included the base line forecast of future natural gas prices as previously discussed as well as prices reflecting a 50% and 100% increase in the base line forecast. These three gas scenarios quantify the sensitivity of the analysis to variable natural gas prices. Chart G shows the natural gas price for each scenario for several years in the forecast period, as well as EIA's projection for reference.

CHART G

Natural Gas Price Forecasts @Henry Hub ($ per MMBTU)							
	2013	**2014**	**2015**	**2017**	**2020**	**2030**	**2035**
SCEG Baseline	$3.61	$4.01	$4.13	$4.39	$4.81	$6.51	$7.58
50% Higher Scenario	$5.41	$6.01	$6.20	$6.58	$7.21	$9.77	$11.37
100% Higher Scenario	$7.21	$8.02	$8.26	$8.78	$9.62	$13.02	$15.16
EIA 2012 Forecast	$4.24	$4.41	$4.62	$4.79	$5.39	$8.95	$11.67

The first combined cycle plant under the gas resource scenario would go on line in 2017. Under the 50% Higher Scenario for gas prices, the natural gas price would be about $6.58 per MMBTU in 2017, a price which is well within the historical range of natural gas prices. In 2035, the gas price shown in the 50% Higher Scenario is almost identical to the EIA forecast.

The 100% Higher Scenario for gas prices produces prices which reflect how the gas resource strategy will perform if current gas price forecasts underestimate future gas prices by a wide margin.

b. CO_2 Cost Scenarios - The CO_2 cost scenarios were $0, $15 and $30 per ton beginning in 2017 and escalating at 5%.

In light of current national environmental policies, CO_2 costs at $0 per ton are not a realistic expectation for the long term. However, the $0 per ton CO_2 scenario provides a useful lower bound to test the sensitivity of the study to this input.

CO_2 costs at $15 per ton are also unlikely. For CO_2 costs to be useful in limiting emissions, they must be set high enough to change behavior on a broad scale. Otherwise, CO_2 emitting parties will choose to pay the CO_2 cost as they would any other tax and continue to discharge CO_2 at current levels. A CO_2 cost of $15 per ton appears to be too low to change behavior on a broad enough scale for such a charge to meet its goals of reducing emissions in a meaningful or comprehensive way. The $15 per ton scenario is modeled here only because it was modeled in the 2008 Study and formed a basis for Dr. Cooper's calculation based on that study.

SCE&G believes that a $30 per ton CO_2 cost is the lowest reasonable CO_2 cost that should be considered in this context. In the exhibits to his testimony, Dr. Cooper reproduces charts indicating a $40 per ton CO_2 cost to be a reasonable assumption as to the future level of such a cost.

For a CO_2 charge to result in progressive decline in CO_2 discharges, it must rise at a regular and meaningful rate. CO_2 legislation proposed before the recent recession included escalation rates applicable to the charge imposed in the range of 5%. Escalation at that rate would serve the purpose of ratcheting up the costs of CO_2 emissions and progressively discouraging them. CO_2 costs are not effective unless they accomplish this result. For that reason, the study assumes that CO_2 costs escalate at that rate after they are imposed.

c. Load Forecasts Scenarios - Three scenarios representing variations of the base case load forecast scenarios were modeled. They included the base case forecast and load forecast scenarios where the load was 5% higher and 5% lower than the base case. These higher and lower load scenarios were modeled to test the sensitivity of the analysis to variability in load due to factors such as increased economic activity or increased rates of energy conservation The 5% plus or minus load scenarios provide for a reasonable assessment of possible variation in load on the system.

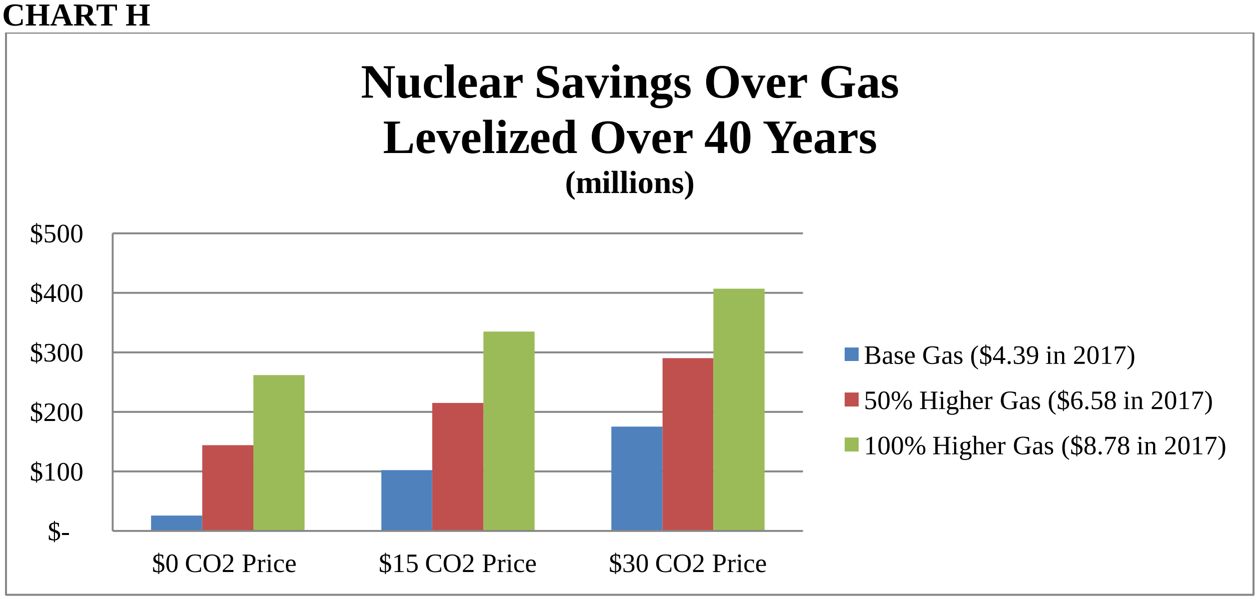
Dispatch Modeling

For each of the 54 combinations of 27 scenarios and 2 generation strategies, a simulation of the generation system dispatch was run using the PROSYM dispatch model. The PROSYM model is licensed from Ventyx and is widely used in the utility industry. This model determined how each generation resource on the system would be dispatched under each scenario over the 40 year planning horizon. Modeling the dispatch of the system using the PROSYM model produced both fuel cost and variable O&M costs for each scenario for each of the 40 years of the planning period. These fuel costs and variable O&M costs generated by the PROSYM model were then combined with the capital costs and other fixed costs for each scenario to determine a levelized annual cost for each of the 27 scenarios over the 40 year planning horizon.

Scenario Results

The results of the modeling are set forth below in Chart H. This chart shows the savings from continuing to construct the Units based on three sets of assumptions as to future gas prices, and based on CO_2 costs of $0, $15 and $30 evaluated against SCE&G's base case scenario for future load. SCE&G believes that the most reasonable scenario for planning purposes is the scenario that models a $30 CO_2 cost and gas prices that are 50% higher than the current SCE&G gas forecast, which is lower than the EIA forecast. That analysis shows that the nuclear strategy is less costly than gas by a levelized amount of $290 million per year for 40 years.

CHART H



The numerical results of the scenarios shown in Chart H are set forth in Chart I below:

CHART I
Base Load Scenario

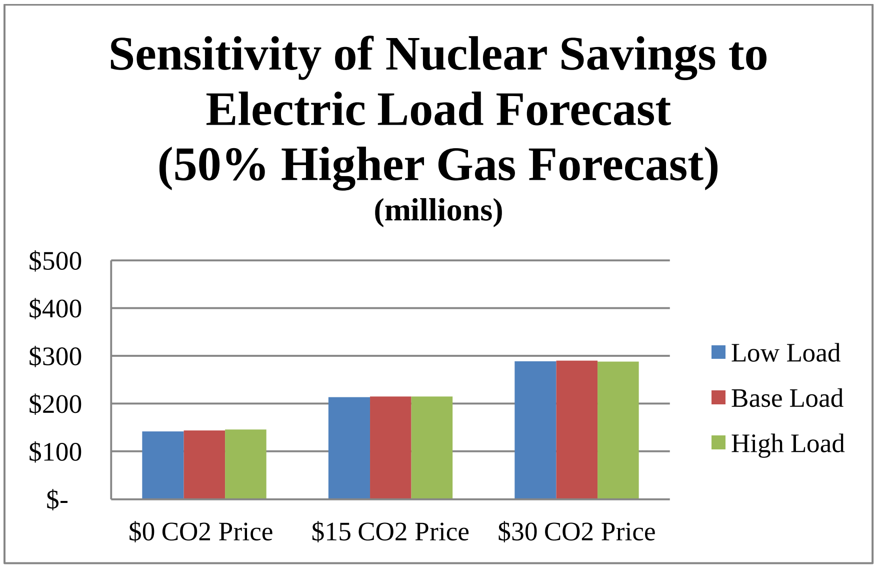
Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years ($MM)			
	Base Gas	**50% Higher Gas**	**100% Higher Gas**
$0 CO2 Price	**$26**	**$144**	**$262**
$15 CO2 Price	**$102**	**$215**	**$335**
$30 CO2 Price	**$175**	**$290**	**$407**

This Chart highlights several critical points. First, completing the nuclear construction program is more economical than switching to a gas resource strategy across all scenarios modeled. In not one case is gas less costly than nuclear. The lowest level of nuclear advantage is a levelized annual advantage of approximately $26 million. This occurs using base gas price assumptions and CO_2 prices at $0 per ton. In the 2008 Studies, the $0 per ton CO_2 scenario with low gas prices resulted in nuclear being more costly than gas by $44 million.

In this series of scenarios, the nuclear strategy had the highest cost advantage over gas in the 100% Higher Gas scenario with a $30 per ton CO_2 price. In that scenario, the nuclear strategy was more cost effective than the gas resource strategy by a levelized amount of $407 million per year. As mentioned above, the scenario with the set of assumptions that SCE&G believes to be most reasonable for planning purposes is 50% higher gas prices with $30 per ton CO_2 where nuclear has a cost advantage over gas of $290 million per year.

Studies were run at different assumptions as to future levels of system load to determine whether the studies' results were sensitive to changes in future electric load forecasts. Chart J shows results calculated using the base load forecast side by side with result calculated using load forecasts that have been increased by 5% and decreased by 5%. The chart shows very little variability in results based on changes in the load forecast.

CHART J



The scenario results reported on Chart J are for the 50% Higher Gas scenario. The Base Gas and 100% Higher Gas scenarios were modeled in the same way. The resulting charts are attached as Appendix 3 and the underlying data is attached as Appendix 4. They show a similar alignment of results. Collectively, these charts show that the cost advantage of the nuclear strategy over the natural gas resource strategy is consistent whether electric loads are greater or less than anticipated in the future.

There are several other inferences that can be drawn from these results of testing the nuclear and the gas resource strategies across these 27 scenarios. First, the advantage that the nuclear strategy has over the gas strategy is not dependent on load growth forecasts. Forecasts for load growth are currently very low. But even if the current load growth projections turn out to be high because of DSM, energy efficiency or distributed or alternative generation, the nuclear advantage is not materially reduced.

Second, the study shows that the comparative economics of the nuclear and natural gas resource strategies swing widely based on gas price forecasts and future CO_2 cost assumptions. This shows that the economics of the gas resource strategy are very sensitive to swings in natural gas prices and CO_2 costs. This confirms that a resource strategy dependent of natural gas generation significantly increases SCE&G's exposure to fossil-fuel volatility and environmental cost increases.

Conclusion

The results of this study demonstrate the analysis that Dr. Lynch presented to the Commission in his rebuttal testimony in Docket No. 2012-203-E was entirely correct. A full system dispatch model, run over a 40 year planning cycle, and using updated information on relevant parameters shows that the forecasts of reduced future natural gas prices identified by Dr. Cooper are more than fully offset by the reduced cost to complete the Units and other factors. The most reasonable estimate of the cost advantage of completing the Units is $290 million per year for 40 years. This study confirms that the nuclear strategy remains the strategy best able to provide favorable results over a broad range of future operating conditions.

SCE&G Forecast of Summer Loads and Resources - 2012 IRP (Reference Scenario)

	YEAR	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Load Forecast																
1	Baseline Trend	4989	5030	5156	5268	5411	5531	5624	5725	5842	5946	6058	6177	6299	6419	6540
2	EE Impact	-21	-37	-79	-111	-144	-177	-211	-247	-288	-334	-365	-400	-437	-476	-518
3	Gross Territorial Peak	4968	4993	5077	5157	5267	5354	5413	5478	5554	5612	5693	5777	5862	5943	6022
4	Demand Response	-218	-221	-225	-228	-232	-235	-237	-239	-241	-244	-246	-248	-250	-252	-254
5	Net Territorial Peak	4750	4772	4852	4929	5035	5119	5176	5239	5313	5368	5447	5529	5612	5691	5768
6	Firm Contract Sales	250														
7	Total Firm Obligation	5000	4772	4852	4929	5035	5119	5176	5239	5313	5368	5447	5529	5612	5691	5768
System Capacity																
8	Existing	5689	5689	5599	5599	5599	5599	5918	6187	6187	6187	6187	6280	6373	6466	6559
	Additions															
9	Peaking/Intermediate											93	93	93	93	93
10	Baseload						614	614								
11	Other		-90				-295	-345								
12	Total System Capacity	5689	5599	5599	5599	5599	5918	6187	6187	6187	6187	6280	6373	6466	6559	6652
13	Firm Annual Purchase				25	150										
14	Total Production Capability	5689	5599	5599	5624	5749	5918	6187	6187	6187	6187	6280	6373	6466	6559	6652
Reserves																
15	Margin (L14-L7)	689	827	747	695	714	799	1011	948	874	819	833	844	854	868	884
16	% Reserve Margin (L15/L7)	13.8%	17.3%	15.4%	14.1%	14.2%	15.6%	19.5%	18.1%	16.5%	15.3%	15.3%	15.3%	15.2%	15.3%	15.3%
17	% NERC Res.Mrgn L15/(L7-L4)	13.2%	16.6%	14.7%	13.5%	13.6%	14.9%	18.7%	17.3%	15.7%	14.6%	14.6%	14.6%	14.6%	14.6%	14.7%

Note: L17 shows the reserve margin calculated according to NERC's new definition. See the following link for details:
http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf

Exhibit 1

RESTATED and UPDATED CONSTRUCTION EXPENDITURES
(Thousands of $)

V.C. Summer Units 2 and 3 - Summary of SCE&G Capital Cost Components

Actual through March 2012* plus Projected

CONFIDENTIAL

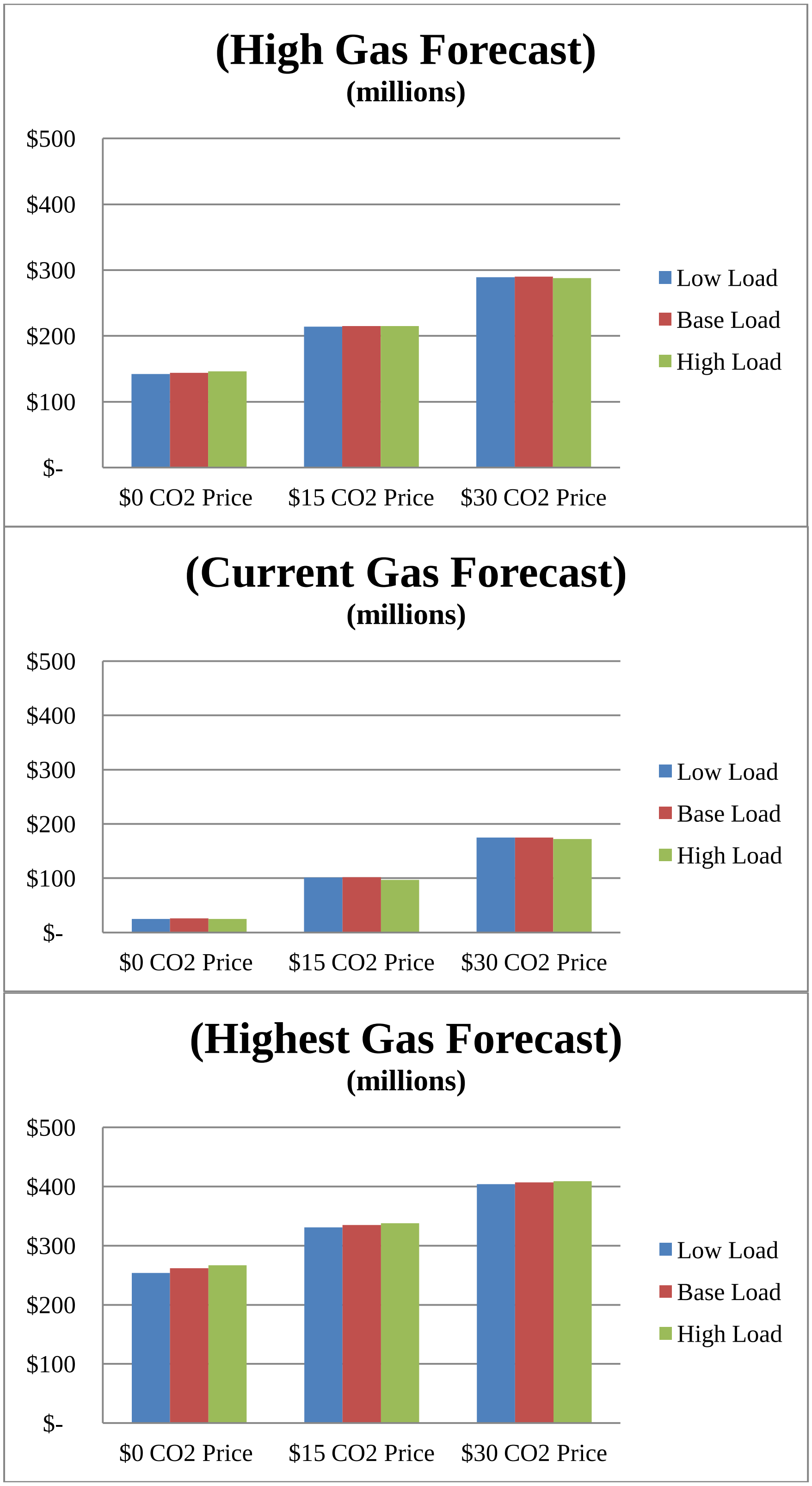
		Actual					Projected						
Plant Cost Categories	**Total**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Fixed with No Adjustment	[redacted]												
Firm with Fixed Adjustment A													
Firm with Fixed Adjustment B													
Firm with Indexed Adjustment													
Actual Craft Wages													
Non-Labor Costs													
Time & Materials													
Owners Costs													
Transmission Costs	329,512	-	26	724	927	11,984	57,206	56,903	57,508	77,990	64,727	1,537	-
Total Base Project Costs(2007 $)	4,553,355	21,723	97,386	319,073	374,810	314,977	614,173	782,238	793,879	648,780	386,537	142,999	56,781
Total Project Escalation	970,629	-	3,519	20,930	23,741	34,084	99,789	169,965	215,848	184,800	134,815	58,409	24,729
Total Revised Project Cash Flow	5,523,984	21,723	100,905	340,003	398,551	349,061	713,961	952,204	1,009,727	833,579	521,351	201,408	81,510
Cumulative Project Cash Flow(Revised)		21,723	122,629	462,632	861,183	1,210,244	1,924,205	2,876,409	3,886,136	4,719,715	5,241,066	5,442,474	5,523,984
AFUDC(Capitalized Interest)	237,926	645	3,497	10,564	17,150	14,218	20,462	38,446	42,934	40,958	27,518	15,391	6,144
Gross Construction	5,761,910	22,368	104,403	350,567	415,701	363,278	734,424	990,649	1,052,661	874,537	548,870	216,798	87,654
Construction Work in Progress		22,368	126,771	477,338	893,039	1,256,317	1,990,741	2,981,390	4,034,051	4,908,588	5,457,458	5,674,257	5,761,910

*Applicable index escalation rates for 2012 are estimated. Escalation is subject to restatement when actual indices for 2012 are final.

Notes:
Current Period AFUDC rate applied | 5.28%

Escalation rates vary from reporting period to reporting period according to the terms of Commission Order 2009-104(A).
These projections reflect current escalation rates. Future changes in escalation rates could substatially change these projections.
The AFUDC rate applied is the current SCE&G rate. AFUDC rates can vary with changes in market interest rates,
SCE&G's embedded cost of capital, capitalization ratios, construction work in process, and SCE&G's short-term debt outstanding.

Sensitivity of Nuclear Savings to Electric Load Forecast



Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years

($MM)

Base Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$26	$144	$262
$15 CO2 Price	$102	$215	$335
$30 CO2 Price	$175	$290	$407

High Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$25	$146	$267
$15 CO2 Price	$97	$215	$338
$30 CO2 Price	$172	$288	$409

Low Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$25	$142	$254
$15 CO2 Price	$101	$214	$331
$30 CO2 Price	$175	$289	$404

REBUTTAL TESTIMONY

OF

JOSEPH M. LYNCH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2012-203-E

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Joseph M. Lynch and I am Manager of Resource Planning for South Carolina Electric & Gas Company ("SCE&G" or the "Company").

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from St. Francis College in Brooklyn, New York, with a Bachelor of Science degree in mathematics. From the University of South Carolina, I received a Master of Arts degree in mathematics, an MBA and a Ph.D. in management science and finance. I was employed by SCE&G as a Senior Budget Analyst in 1977 to develop econometric models to forecast electric sales and revenue. In 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and in 1991, I was promoted to my current position of Manager of Resource Planning.

Q. WHAT ARE YOUR CURRENT DUTIES AS MANAGER OF RESOURCE PLANNING?

A. As Manager of Resource Planning I am responsible for producing SCE&G's forecast of energy, peak demand and revenue; for developing the Company's generation expansion plans; and for overseeing the Company's load research program.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION?

A. I have, on a number of occasions.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. My testimony points out certain problems with the positions asserted by the Sierra Club through the testimony of its witness Dr. Cooper. Specifically, I support Mr. Marsh's testimony that points out the problems in the analytical approach that Dr. Cooper uses. I provide further support for Mr. Marsh's conclusion that natural gas prices are highly volatile, and that our knowledge of future natural gas prices is too limited and uncertain to allow a utility to rely on a single forecast of future prices in planning for future base load generation capacity. All other considerations aside, I also show that because of the investment that SCE&G has made to date in the V. C. Summer Nuclear Units 2 and 3 (the "Units"), going forward with construction of them is clearly superior from a pure cost basis even assuming low natural gas prices.

Q. DO YOU AGREE WITH MR. MARSH'S ASSESSMENT OF THE FLAWS IN DR. COOPER'S ANALYSIS?

A. I agree that Dr. Cooper's analysis is flawed for many reasons. Most importantly, he looks only at one set of data as to future gas costs. This is not how utility planning decisions are made. Mr. Marsh's testimony explains this very well.

Q. IN HIS DIRECT TESTIMONY DR. COOPER ARGUES THAT THE "COLLAPSE OF GAS PRICES HAS BEEN DRAMATIC" AND THAT THE EIA IS CURRENTLY PROJECTING NATURAL GAS PRICES TO BE 62% LESS THAN SCE&G'S BASELINE PROJECTIONS IN THE 2008 CASE. SHOULD SCE&G ABANDON CONSTRUCTION OF ITS NUCLEAR UNITS BECAUSE OF THIS?

A. Of course not. The natural gas markets experience a great deal of volatility in prices and planners see as much or more volatility in the projections of future natural gas prices. In Exhibit No. __ (JML-1), I show a graph of EIA's current natural gas price projections using data contained in their Annual Energy Outlook ("AEO") 2012 forecast as well as that contained in their AEO 2009 forecast. The 2012 forecast is about 60% or so less than their 2009 forecast. So three years ago the EIA did not foresee that a dramatic collapse in natural gas prices coming. By the same token, EIA may not be able to foresee a dramatic reversal in prices in another three years if that were coming.

Q. DO YOU PUT MUCH CONFIDENCE IN THE EIA'S NATURAL GAS PRICE PROJECTIONS?

A. Planners, if they are prudent, do not put much confidence in anyone's projection of natural gas prices. That is why almost all resource planning studies involve scenario planning and sensitivity analysis around the most uncertain drivers of cost. The price of fossil fuels is one of the most volatile and uncertain drivers of energy costs. Each year the EIA publishes an analysis of the accuracy of its natural gas price forecast. Exhibit No. __ (JML-2) shows a portion of EIA's error analysis of its natural gas price projections, which shows the percent error in their past forecasts. An important thing to notice in the table is that most entries show sizable errors even in short term predictions and there is no entry with a 0% error. This means that the EIA's forecast is almost always wrong. It is only a question of how wrong.

Q. DOES THE EIA PROVIDE SOME INDICATION OF THE UNCERTAINTY SURROUNDING ITS NATURAL GAS PROJECTIONS?

A. It does. The error analysis I just discussed provides one indication of uncertainty. Another is a confidence interval that the EIA publishes with respect to its projection of short-range prices. In Exhibit No. __ (JML-3), I show an EIA chart containing a 95% confidence interval that EIA has computed around its forecast of gas prices through 2013. This chart suggests the possibility of prices in December 2013 reaching as high as $7.76 per MMBTU and as low as $2.11 with an expected price of $3.63. Clearly the EIA sees much uncertainty in its forecasts of gas prices even in the next two years.

Q. IS THE UNCERTAINTY IN NATURAL GAS PRICES BALANCED, THAT IS, IS THE RISK OF HIGHER PRICES JUST AS GREAT AS THE RISK OF LOWER PRICES?

A. No, the risk of higher prices is much greater than the risk of lower prices. Common sense and economics would suggest that natural gas producers would not produce and sell gas at a loss, at least not for very long, so there is a floor on how low gas prices can go. On the other hand, experience tells us that, if there is a ceiling, it is fairly high. The unbalanced nature of price risk for natural gas can be demonstrated in EIA's confidence interval I just discussed. The upper bound of the 95% confidence interval is 214% greater than the mean forecast while the lower bound is 42% lower. This means that there is an equal probability of prices being 214% higher as there is of them being 42% lower than the expected price. Clearly the upside risk is greater.

Q. ARE THERE ECONOMIC FORCES THAT WOULD TEND TO PUSH NATURAL GAS PRICES HIGHER?

A. Yes. There are two categories of factors that come to mind: supply and demand forces and environmental regulations. As to supply and demand, natural gas prices are low now because of an abundance of supply being provided by the new production technology of hydraulic fracturing, or fracking. Because of the low prices, the demand for natural gas is increasing and this will put upward pressure on the price. For example, natural gas generation is displacing a high percentage of coal generation in the day-to-day dispatch of generating systems throughout the country. This will tend to push the cost of gas generation toward the cost of coal generation, which in today's market is higher. In the longer term, there are gas exporters seeking authority to build liquefaction capacity to sell domestically produced natural gas in the international market.[1] Today, U.S. prices for natural gas are much lower than prices internationally.[2] If export sales increase, this will increase demand for domestically produced natural gas. A high level of exports would link domestic prices more closely to the global energy market and global prices. Furthermore, low gas prices in the United States are leading to expansion in gas-intensive industries like petrochemicals, pharmaceuticals and other businesses that use gas as a chemical feedstock or energy source.[3]

As to environmental regulations, the effect of environmental regulations will take at least two forms. Recently promulgated EPA air emissions regulations, such as those Mr. Byrne discusses, are forcing the early retirement of coal capacity which cannot economically be scrubbed. Given the cost of carbon sequestration, newly issued CO_2 regulations have taken new coal generation off the table as a

[1] Project sponsors are seeking Federal approval to export domestic natural gas" April 24, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=5970/.
[2] Id.
[3] Accenture, North America Flexes it Manufacturing Muscle,http://www.accenture.com/us-en/outlook/Pages/outlook-journal-2012-north-america-flexes-industrial-muscle.aspx?c=mc_myoutlook3-_10000009&n=emc_0712

means for meeting future electric demand. Electric utilities will be meeting much of their future capacity needs through the addition of new gas fired generation. This will increase the demand for natural gas and put still more upward pressure on gas prices. Increasing reliance of natural gas as a fuel for electric generation will also create the need for new pipeline capacity to deliver gas in the required volumes, which involves construction and permitting costs and risks, which can lead to higher costs. Of course, if you burn gas, you emit carbon, so another risk of gas generation is the risk that CO_2 costs will be imposed directly on gas as a fuel.

The other form of regulation deals with the technique of fracking. There is concern in the environmental community that the technique is harmful to the environment and requires more regulation. Such regulations would increase the cost of producing natural gas and as a result would also increase the price of gas in the market. How these developments will progress is uncertain, but they indicate that there are forces at work in the economy that could cause today's forecasts of future gas prices to prove inaccurate.

Q. WHY DO YOU SAY THAT COAL IS "OFF THE TABLE" FOR ELECTRIC GENERATION TODAY?

A. On May 27, 2012, the Environmental Protection Agency issued new regulations based on a finding that CO_2 should be regulated as an air pollutant. The new regulations require all new or refurbished electric generation facilities to meet CO_2 discharge limits which are based on the expected emissions from a combined-cycle natural gas generation unit. This means that given current state of carbon sequestration technology, new coal generation or refurbished coal plants are not likely to be permitted for operation in the United States. Apart from nuclear generation, there is now only one type of dispatchable base load/intermediate load generation resource that can be built in most of the United States. That is combined-cycle gas generation.

Q. DR. COOPER ESTIMATES THAT THE LOW GAS PRICES CURRENTLY PROJECTED BY THE EIA IMPLIES A $115 MILLION REDUCTION IN THE LEVELIZED COST OF A NATURAL GAS FIRED GENERATION STRATEGY AND THAT SCE&G SHOULD THEREFORE ABANDON THE CONSTRUCTION OF ITS NUCLEAR UNITS FOR ECONOMIC REASONS. DO YOU AGREE?

A. Absolutely not. I have demonstrated that there is a great deal of uncertainty in natural gas prices and in their projection. Prudent resource planning decisions cannot be made based on a single scenario of natural gas price projections. I have also shown that the likelihood of higher gas prices is much greater than that of likelihood of lower gas prices. Therefore, there is a greater likelihood that the $115 million advantage that Dr. Cooper calculates will decrease or disappear than that this advantage will get larger.

Q. FOR THE SAKE OF ARGUMENT ASSUME THAT SCE&G PUTS ASIDE THE PRUDENT PRACTICE OF USING SCENARIO PLANNING AND SENSITIVITY ANALYSIS IN RESOURCE PLANNING STUDIES AND ACCEPTS DR. COOPER'S APPROACH OF USING ONE SCENARIO OF

LOW GAS PRICES OVER 40 YEARS TO MAKE PLANNING DECISIONS. WOULD YOU AGREE BASED ON THE RESULTING ECONOMICS THAT SCE&G SHOULD ABANDON ITS NUCLEAR CONSTRUCTION AND BUILD NATURAL GAS FIRED GENERATION?

A. Absolutely not. Assuming that natural gas prices will be low for the next 40 years and further assuming that Dr. Cooper is correct in his calculation that this results in a $115 million reduction in the levelized cost of a natural gas generation strategy, you still need to look at those important drivers of cost that have changed related to the nuclear generation strategy going forward.

Q. PLEASE EXPLAIN.

A. At least two changes have occurred since the original studies were run that would make a material difference in the cost of the nuclear strategy. One relates to the cost of the Units. In his direct testimony Mr. Byrne notes that the projected cost of the nuclear construction is about 8.7% or $551 million lower than the forecasts on which the original studies were run. Over a 40-year period, the levelized carrying cost of investing in nuclear generation is 16%. This means that on a levelized basis, every dollar invested in the Units equates to $0.16 per year in capital related costs on average during the 40-year period. This levelized carrying cost includes all the costs of carrying the nuclear investment, including depreciation, taxes, insurance, interest and so forth. Using a 16% levelized carrying charge for nuclear investments, and applying it to the $551 million reduction in the cost of the Units we are now forecasting, we can compute the difference that this reduction in cost makes to the levelized cost of the nuclear generation strategy. The result is that because of the $551 million reduction in the construction cost forecast, the levelized cost of nuclear generation is reduced by about $88 million ($551 million * 0.16%) per year over the 40 year planning horizon for the study.

Furthermore it is well recognized in utility planning practice that when making decisions about investments going forward, it is only the going-forward costs that are relevant. These are the costs that are left to be spent. If the question is whether or not SCE&G should complete the nuclear Units, only the cost of completing the Units is relevant.

In Exhibit 1 of her testimony, Ms. Walker reports that about 25% of the construction costs for the Units have already been spent and 75% remain to be spent to complete the project. This means that the levelized cost of the nuclear generation scenario should be reduced by $230 million ($5,762 million * 0.16 * 0.25), where $5,762 million is the current cost of the Units, 25% is the amount that has been spent and 16% is the levelized carrying cost of nuclear investment. Thus to update the 2008 study to current conditions, the levelized cost of the nuclear generation strategy should be reduced by a total of $318 million to reflect the fact that the cost of the Units has declined by $551 million and only 75% of that lower cost remains to be spent.

Q. WHAT ABOUT THE ADDITIONAL COSTS THAT SCE&G MIGHT HAVE TO PAY TO ITS CONTRACTORS AND OTHERS TO ABANDON THE UNITS AT THIS TIME?

A. As Mr. Byrne discusses, SCE&G would have to pay additional costs to its contractors and others to abandon construction of the Units and switch to a gas strategy. Those costs have not been quantified. But at this point in the project, incurring them would be a necessary part of moving to a gas strategy. Because these costs are not included in my analysis, it understates the advantages that the nuclear strategy has over gas to that extent. But this would only cause the advantage of nuclear strategy to go up. The cost of abandonment would increase the value of continuing with nuclear construction compared to switching to a gas strategy.

Q. WHAT THEN IS YOUR CONCLUSION BASED ON THE UPDATED ECONOMICS?

A. The economics clearly demonstrate that the nuclear construction should continue. Given current capital cost forecasts and the value of investment to date, the levelized cost of the nuclear generation strategy is reduced by $318 million. Even if the levelized cost of the gas generation strategy is reduced by $115 million as Dr. Cooper suggests, the nuclear strategy maintains its economic advantage by a wide margin.

Q. WHICH ADJUSTMENT DO YOU CONSIDER THE MOST RELIABLE -- DR. COOPER'S ADJUSTMENT OF $115 MILLION BASED ON AN

ASSUMPTION OF LOW GAS PRICES OVER THE NEXT 40 YEARS OR THE $318 MILLION ADJUSTMENT BASED ON THE NUCLEAR CONSTRUCTION COSTS?

A. I have much more confidence in the $318 million adjustment than the $115 million. More than two-thirds of the cost left to be spent under the EPC contract are fixed or subject to fixed escalation rates. Of course the 25% of the cost of the Units that has already been spent is fully known and measurable. On the other hand, I have already discussed the volatility and uncertainty of prices in the natural gas market. The $115 million adjustment to the natural gas generation strategy is based on an assumption of low gas prices over the next 40 years which is very uncertain. All indications are that the uncertainty of the gas price forecast is much greater that the uncertainty surrounding the cost of completing the construction cost of the Units.

Q. DR. COOPER TESTIFIES THAT THE COST OF THE NATURAL GAS GENERATION STRATEGY COULD BE REDUCED BY AS MUCH AS $200 MILLION IF A ZERO COST FOR CO_2 EMISSIONS IS ASSUMED IN ADDITION TO LOW NATURAL GAS PRICES. HAVE YOU CONSIDERED THIS IN YOUR ANALYSIS?

A. In its 2008 studies, SCE&G had assumed in its base case scenario a cost of $15 per ton of CO_2 emitted which gave the nuclear strategy an $88 million advantage over the natural gas generation strategy in levelized costs.

Dr. Cooper testifies at one point that if a zero cost per CO_2 ton is assumed, then the $87 million could be added to the $115 million discussed above thereby producing a $200 million reduction in levelized costs for the natural gas generation strategy. However, Dr. Cooper subsequently testifies that the Commission cannot "ignore the carbon issue" so I assumed that his discussion about a $200 million reduction was meant more as commentary than serious economic analysis.

Q. CAN THE COMMISSION IGNORE THE CARBON ISSUE?

A. I agree with Dr. Cooper that the Commission cannot ignore the carbon issue. The EPA has ruled that CO2 emissions endanger human health, and the U.S. Supreme Court has ruled that under the Clean Air Act if the EPA makes such an endangerment finding, then it must regulate CO_2 emissions. Carbon emission cost, by the way, can come as taxes, cap and trade mechanisms, or mandatory capture and sequestration requirements. Each of these approaches imposes costs. For purpose of our studies, what form these costs takes is not particularly important.

Q. ASSUME FOR ARGUMENT SAKE THAT THE EPA REVERSES ITS ENDANGERMENT FINDING AND THAT THE COST OF CO_2 EMISSION IS ZERO IN THE FUTURE AND ASSUME FURTHER THE NATURAL GAS PRICES STAY LOW OVER THE NEXT 40 YEARS AND CONSEQUENTLY THAT THE NATURAL GAS GENERATION STRATEGY IS $200 MILLION LESS RELATIVE TO THE NUCLEAR

STRATEGY IN LEVELIZED COSTS. BASED ON ECONOMICS SHOULD SCE&G ABANDON THE NUCLEAR CONSTRUCTION AND BUILD GAS FIRED PLANTS UNDER THESE ASSUMPTIONS?

A. Absolutely not. First I should repeat that important resource planning decisions should be based on thorough studies using scenario planning and sensitivity analysis. All that Dr. Cooper's analysis demonstrates is that scenarios can be imagined in which gas might be more economical than nuclear. Even accepting Dr. Cooper's approach, which I cannot do, SCE&G should not abandon the nuclear construction because, as already discussed, updated information on construction costs show at least a $318 million reduction in the cost of the nuclear strategy based on where we stand today. Even when compared to the $200 million reduction for the natural gas strategy which Dr. Cooper puts forward, and which even he does not seem to fully accept, the economic advantage of the nuclear strategy remains.

Q. DR. COOPER MENTIONS A SAVINGS OF $4 BILLION AND POSSIBLY AS MUCH AS $8 BILLION ASSOCIATED WITH HIS ANALYSIS. WHAT DO THESE NUMBERS REPRESENT AND HOW DO THEY RELATE TO THE LEVELIZED COSTS THAT YOU HAVE BEEN DISCUSSING?

A. While Dr. Cooper does not specify how he made his calculation, it seems that his $8 billion number was calculated as the product of 40 years times the annual average levelized savings of $200 million. He makes a similar calculation based on his $115 million levelized savings assertion, and calculates a $4 billion savings. This is not how this calculation would be made in the planning context. The approach that would be used in the planning context would be to compute a present value which is a standard calculation used in economic analysis to determine the accumulated present value of a future revenue stream.

Q. PLEASE EXPLAIN.

A. The accumulated present worth of a future revenue stream gives you the value today of a stream of payments or savings going out into the future. The calculation uses a present value factor that is typically calculated using the cost of capital for the entity in question. Using a weighted cost of capital of 8.7%, which is SCE&G's actual weighted average cost of capital as of December 31, 2011, the accumulated present value factor for a 40-year levelized stream of dollars is 12.05. Thus the accumulated present value for the $200 million levelized stream is $2.4 billion (12.05*$200 million) not $8 billion. A similar calculation can be made for Dr. Cooper's levelized savings calculation of $115 million. In this case the accumulated present value is $1.4 billion (12.05 * $115 million) as opposed to the $4 billion reported by Dr. Cooper.

Q. HOW WOULD YOUR NUMBERS REFLECTING INCREASED SAVINGS FOR THE NUCLEAR STRATEGY COMPARE ON A PRESENT VALUE BASIS?

A. I computed an increase in the levelized savings for the nuclear strategy of $318 million resulting from the reduced capital costs of completing the nuclear Units. The present value of this amount over the planning horizon is $3.9 billion, which compares to the present value of Dr. Cooper's asserted savings for the gas strategy ($115 million levelized with $15 CO_2 costs) of $1.4 billion. Even accepting Dr. Cooper's assumptions as to future gas prices, the cost reduction he computes in the gas strategy is less than half the saving in the nuclear strategy. Compared to $200 million in levelized savings that Dr. Cooper computed, which he admits improperly assumes no CO_2 costs, the results are $2.4 billion in savings for the gas strategy compared to $3.9 billion in savings for the nuclear strategy. Even assuming no CO_2 costs, nuclear savings are still over 60% greater than the savings for gas. Clearly, at this point in the project continuing construction of the nuclear Units is more economical by a very wide margin than abandoning them and pursuing a natural gas strategy. The comparisons are set out in the Chart A, below.

Chart A

Dr. Cooper's Adjustments to Natural Gas Strategy Costs (reduced costs, in millions)	
Low Gas Cost	
Levelized Per Year	$115
Accumulated	$4,000
Present Value	**$1,400**
Low Gas Cost & No CO_2 Cost	
Levelized Per Year	$200
Accumulated	$8,000
Present Value	**$2,400**

SCE&G's Adjustments to Nuclear Strategy Costs (reduced costs, in millions)	
Going-Forward Cost[1]	
Levelized Per Year	$318
Accumulated	-[2]
Present Value	**$3,900**

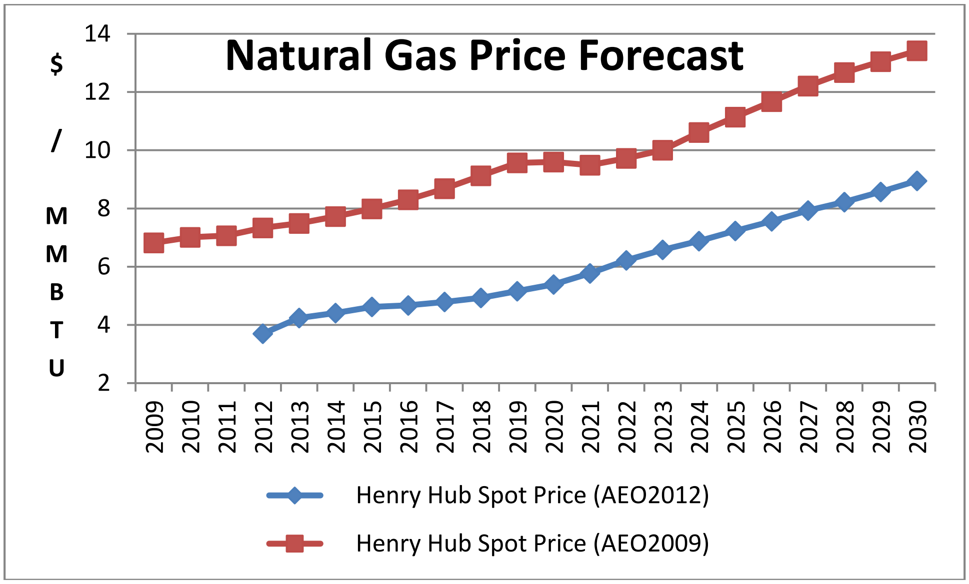
[1] Reflecting reduced construction cost of $551 million and the fact that 25% of the reduced cost of the project has already been spent.
[2] Not computed.

Q. DOES SCE&G SEE AN ADVANTAGE TO ITS NUCLEAR GENERATION STRATEGY THAT GOES BEYOND THE ECONOMIC ISSUES BROUGHT UP BY DR. COOPER AND ADDRESSED IN YOUR TESTIMONY?

A. Yes, it does. Under its nuclear strategy SCE&G will achieve a balanced mix of capacity. In 2019 SCE&G will have 31% nuclear generation, 28% natural gas and 27% coal. This puts SCE&G in a good position to protect its customers and mitigate the cost impacts from the volatility of fossil fuel prices and the uncertainty of future environmental regulations on fossil fuels.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

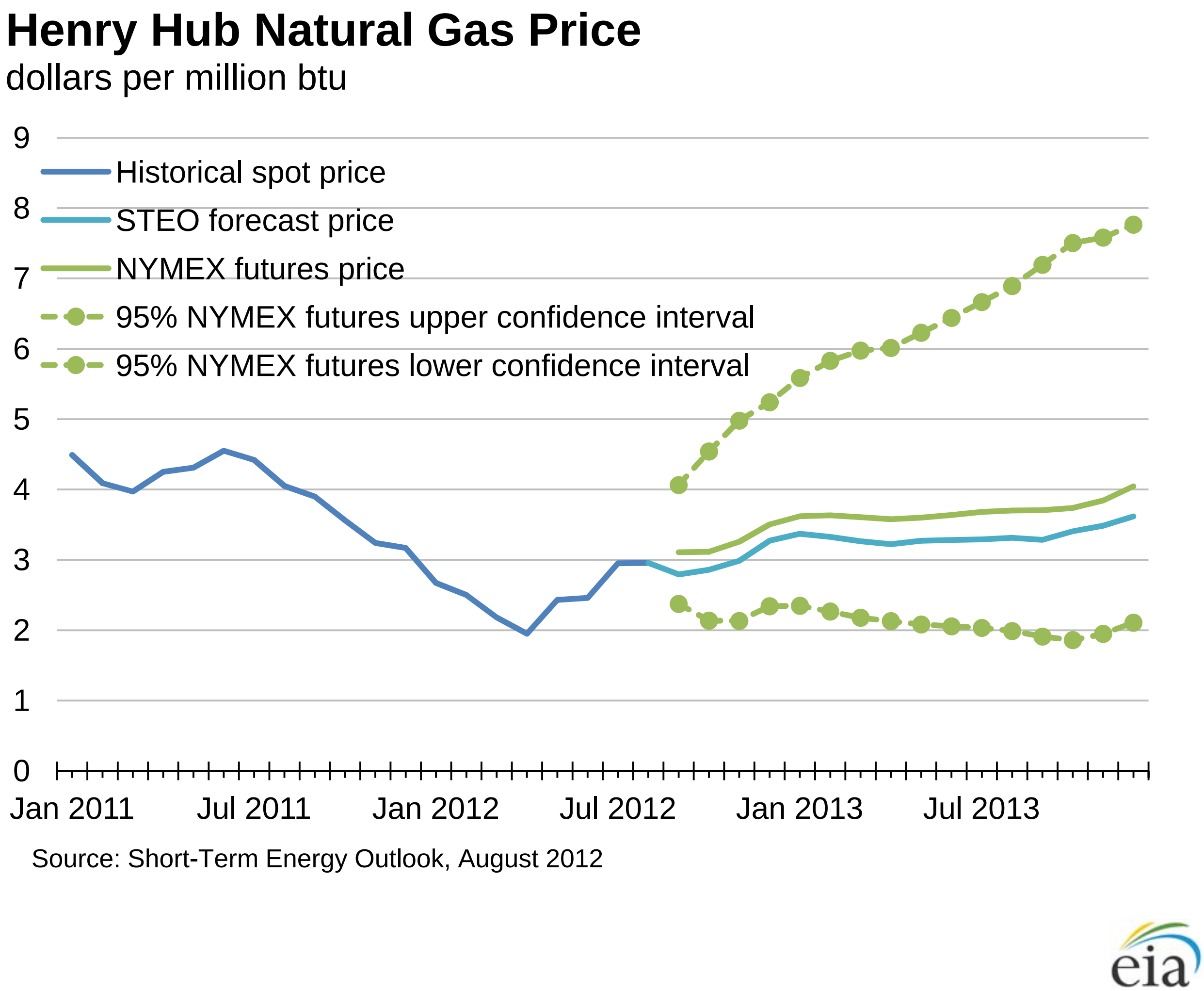

Natural Gas Price Forecast
$ / MMBTU
14
12
10
8
6
4
2
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Henry Hub Spot Price (AEO2012)
Henry Hub Spot Price (AEO2009)

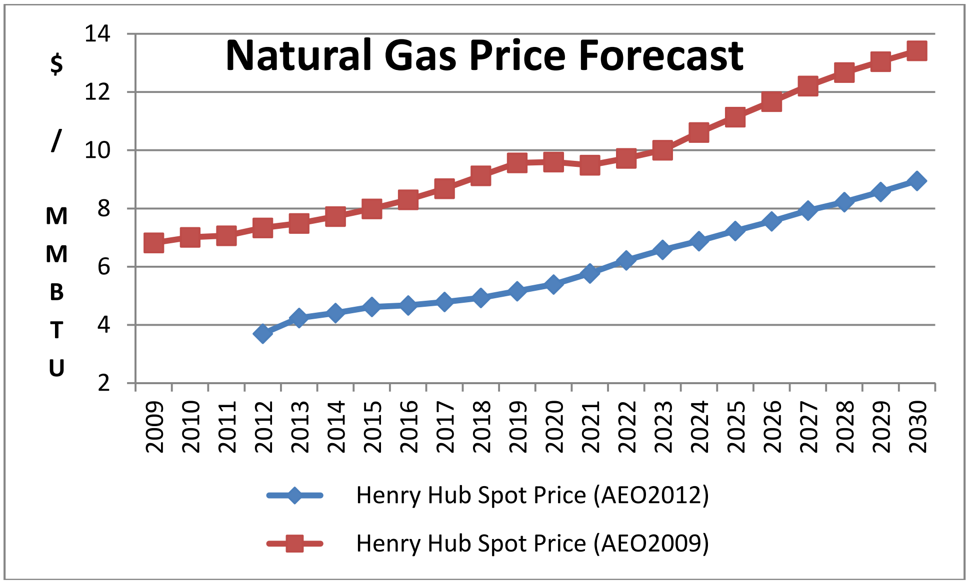
Projected vs. actual
(percent difference)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
AEO 1994	-19.0	-21.5	13.4	-26.4	-29.5	-42.9	-29.4	-21.4	-33.6	51.5	43.3
AEO 1995	-30.2	-27.6	7.1	-27.1	-29.1	-41.8	-28.6	-22.4	-35.3	47.5	36.1
AEO 1996	-40.4	-42.8	-19.4	-49.3	-52.6	-62.9	-55.6	-52.5	-60.9	-10.2	-16.2
AEO 1997	-43.9	-46.6	-25.0	-52.5	-55.5	-65.3	-58.5	-55.7	-63.9	-18.3	-25.2
AEO 1998	-37.2	-40.5	-17.1	-48.4	-52.5	-63.3	-56.3	-53.2	-61.6	-12.7	-19.5
AEO 1999	-40.1	-42.1	-17.8	-48.1	-51.8	-62.4	-54.6	-51.7	-60.8	-11.9	-19.5
AEO 2000	-39.3	-43.3	-21.4	-50.9	-54.0	-63.7	-56.0	-52.5	-61.1	-12.9	-21.0
AEO 2001	-7.8	-12.9	0.8	-43.9	-50.5	-61.4	-53.9	-51.0	-60.2	-11.3	-19.4
AEO 2002		0.6	-30.1	-48.1	-47.9	-59.0	-51.0	-48.3	-57.4	-4.2	-12.3
AEO 2003			-5.6	-33.2	-42.8	-57.1	-50.8	-47.1	-56.0	0.9	-5.0
AEO 2004				1.9	-26.8	-49.3	-41.7	-38.2	-48.9	8.2	-4.0
AEO 2005					-1.4	-24.7	-22.6	-26.9	-46.9	14.8	0.5
AEO 2006						6.5	12.1	4.4	-21.3	61.4	36.7
AEO 2007							7.5	12.1	-11.3	80.2	53.8
AEO 2008								1.9	-13.8	95.5	64.5
AEO 2009									1.1	12.2	15.7
AEO 2010										-7.9	0.2
AEO 2011											-1.0
Average Absolute Percent Difference	32.2	30.9	15.8	39.1	41.2	50.8	41.3	36.0	43.4	27.2	21.9

Sources: Projections: *Annual Energy Outlook*, Reference Case Projections, Various Editions.

Historical Data: U.S. Energy Information Administration, Annual Energy Review 2010, DOE/EIA-0384(2010) (Washington, DC, October 2011) Table 6.7.


Henry Hub Natural Gas Price
dollars per million btu
9
8
7
6
5
4
3
2
1
0
Historical spot price
STEO forecast price
NYMEX futures price
95% NYMEX futures upper confidence interval
95% NYMEX futures lower confidence interval
Jan 2011
Jul 2011
Jan 2012
Jul 2012
Jan 2013
Jul 2013
Source: Short-Term Energy Outlook, August 2012
eia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AEO 2000	-39.3	-43.3	-21.4	-50.9	-54.0	-63.7	-56.0	-52.5	-61.1	-12.9	-21.0
AEO 2001	-7.8	-12.9	0.8	-43.9	-50.5	-61.4	-53.9	-51.0	-60.2	-11.3	-19.4
AEO 2002		0.6	-30.1	-48.1	-47.9	-59.0	-51.0	-48.3	-57.4	-4.2	-12.3
AEO 2003			-5.6	-33.2	-42.8	-57.1	-50.8	-47.1	-56.0	0.9	-5.0
AEO 2004				1.9	-26.8	-49.3	-41.7	-38.2	-48.9	8.2	-4.0
AEO 2005					-1.4	-24.7	-22.6	-26.9	-46.9	14.8	0.5
AEO 2006						6.5	12.1	4.4	-21.3	61.4	36.7
AEO 2007							7.5	12.1	-11.3	80.2	53.8
AEO 2008								1.9	-13.8	95.5	64.5
AEO 2009									1.1	12.2	15.7
AEO 2010										-7.9	0.2
AEO 2011											-1.0
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Sources: Projections: *Annual Energy Outlook*, Reference Case Projections, Various Editions.

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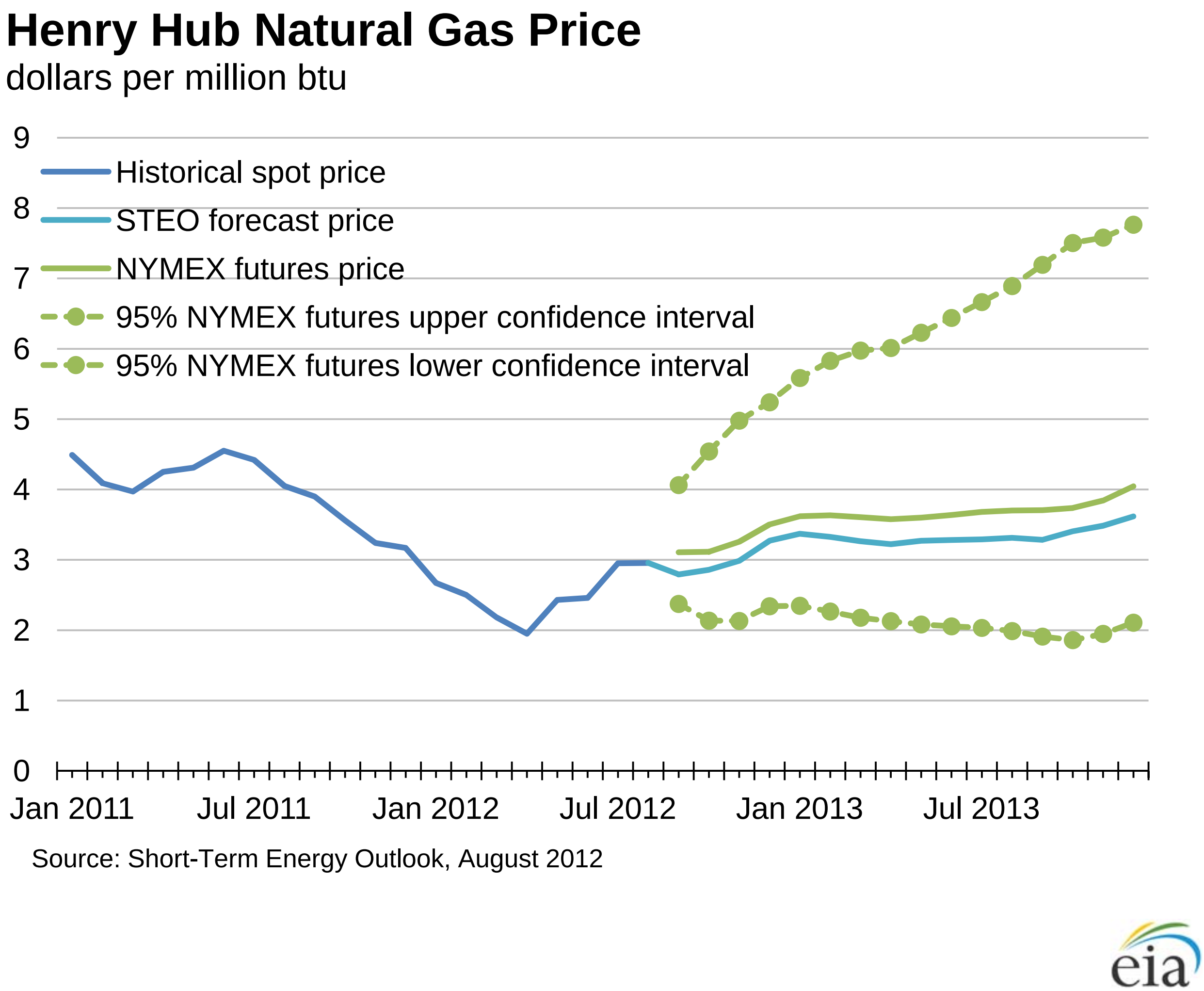
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Historical spot price
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95% NYMEX futures upper confidence interval
95% NYMEX futures lower confidence interval
Jan 2011
Jul 2011
Jan 2012
Jul 2012
Jan 2013
Jul 2013
Source: Short-Term Energy Outlook, August 2012

CORRECTED VERSION

Exhibit_(JML-5)

Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy

May 26, 2015

SCE&G®
A SCANA COMPANY

Introduction

The purpose of this study is to determine if abandoning SCE&G's ongoing nuclear construction program and pursuing a natural gas generation strategy for base load generation needs would benefit retail customers in terms of long-run revenue requirements. SCE&G's management directed the Resource Planning Department to use current data to prepare generation cost studies comparable to those performed in 2008 that supported the original decision to construct the two nuclear units (the Units).

SCE&G has undertaken this exercise expressly reaffirming its position that no single analysis of comparative costs underlies its choice of nuclear generation over gas fired generation alternatives. The goal of base load generation planning is to create a diverse and flexible portfolio of generation units that can perform effectively in multiple sets of conditions over 40 years or more. No single study or series of studies is an effective substitute for informed business judgment exercised with this goal in mind.

This study calculates the incremental revenue requirements on a comparative basis for two strategies. The first is the base case which involves completing the two nuclear units which are presently under construction and scheduled to go into service in 2019 and 2020. When completed, the Units together will provide SCE&G with 1,229 MW. The second strategy is the natural gas resource strategy in which the Units are cancelled at the effective date of March 31, 2015. The Units are replaced by two combined cycle units rated at 614 MWs each which come into service in 2019 and 2020 also.

The principal components of the study and conclusion are set forth below. The inputs to the study have been updated to reflect the most current values available.

Load Forecast and Resource Plans

To compute the revenue requirements of the two strategies over a 40-year planning horizon, the study relies on the load forecast data that were reported in summary form in SCE&G's 2015 Integrated Resource Plan. These load forecasts are updated versions of those that were used in the 2008 planning studies (the 2008 Studies) on which the original Base Load Review Act (BLRA) order was based. Both the nuclear and gas resource strategies are measured against identical load forecasts.

Appendix 1 shows the forecast and the base case scenario resource plan. Both the nuclear capacity and the natural gas combined-cycle capacity are shown on the alternative versions of the resource plan as "base load" capacity entered on line 10 in the table shown in Appendix 1. As was the case with the 2008 Studies, the resource plans for each of the two strategies assumed that, after the base load capacity was added, additional simple-cycle natural gas-fired generation was added to meet subsequent load growth. Comparable amounts of simple cycle generation with comparable capital cost and operating costs were added under each strategy.

Abandoning Nuclear Construction

As of March 31, 2015, SCE&G expects to have spent $3.101 billion on construction of the Units. If SCE&G were to decide to cancel the nuclear construction project, it would be subject to contractual cancellation charges, site decommissioning and stabilization expenses and other abandonment expenses in addition to the $3.101 billion that would already have been spent. SCE&G's best assessment of the amount of those cancellation expenses would be $1.033 billion for a cancellation effective December 31, 2014. This is the cost on a 100% basis (i.e., including Santee Cooper's 45% share in expenses).

Upon cancellation of the project, SCE&G could scrap, sell or salvage certain materials, equipment and work in progress and could use the proceeds to off-set some part of the abandonment expenses. A large component of the spending to date, however, has been for site work, construction of roads, building and bridges on site, the hiring and training of personnel, design and procurement work, and other activities that do not produce salvageable materials. SCE&G estimates that of the amounts spent to date, the salvage value of materials, equipment and work in progress would be approximately $515.8 million on a 100% basis. This $515.8 million would be netted against the gross cancellation cost of $1.033 billion to produce an estimate of the net cancellation cost, not considering the $3.101 billion already spent, of $517 million, again on a 100% basis. SCE&G's customers would be responsible for 55% of this cost or $284 million.

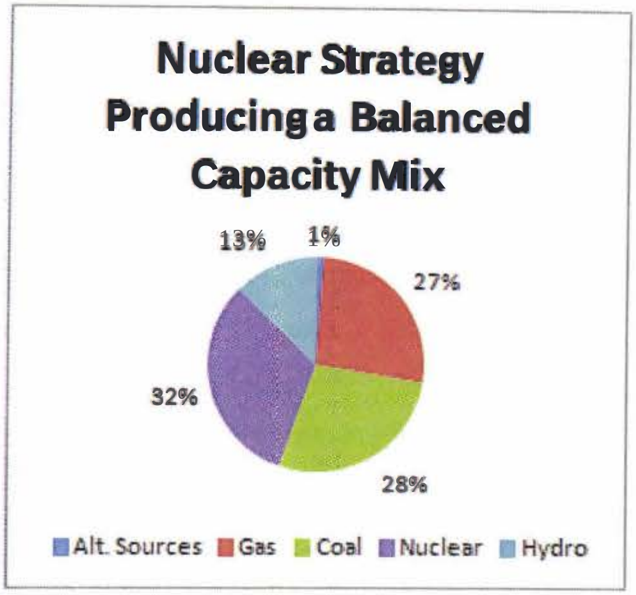
Thus, adding the $3.101 billion spent as of March 31, 2015, and the $284 million in net cancellation costs, the total abandonment cost is estimated to be $3.385 billion.

The model used for comparing the costs of these two strategies computes a levelized cost for capital invested that includes all relevant parameters given the nature of the asset involved. This combination of costs spent to date and additional cost to abandon the project represent a cost that must be borne by the gas resource strategy.

Benefit of a Balanced Capacity Portfolio

A significant advantage of continuing construction of the two nuclear units is that once added to SCE&G's generation fleet, the Units will produce a well balanced capacity portfolio. The following charts show the percent distribution of capacity under a plan of continuing nuclear construction and the alternative of replacing it with natural gas fired capacity.

CHART A



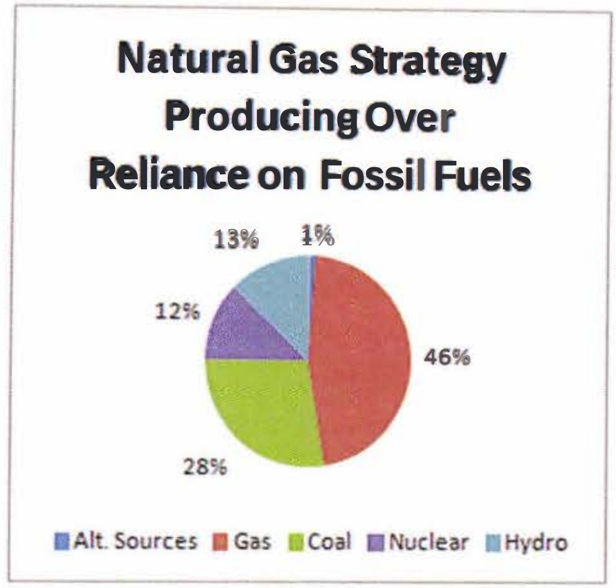


Chart A shows that the Natural Gas Strategy produces a generation system that in 2021 relies on fossil fuels for 73% of its generating capacity. The Nuclear Strategy creates a more balanced portfolio. Such a portfolio better protects customers from unexpectedly high costs in any one fuel source while allowing the utility to take advantage of opportunities in others.

Price of Natural Gas

Chart B shows two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration (EIA) natural gas forecast reported in their 2015 Annual Energy Outlook (AEO). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor projected by the economic forecasting firm IHS Global Insight Inc. to forecast prices beyond three years in the future. This is a methodology that SCE&G has used for a number of years to produce gas forecasts for planning studies. The value of this methodology is that it is simple and objective. However, because all forecasts of future gas prices are subject to error, SCE&G typically tests the results of these studies done using these forecasts through sensitivity analyses that model variations in gas prices.

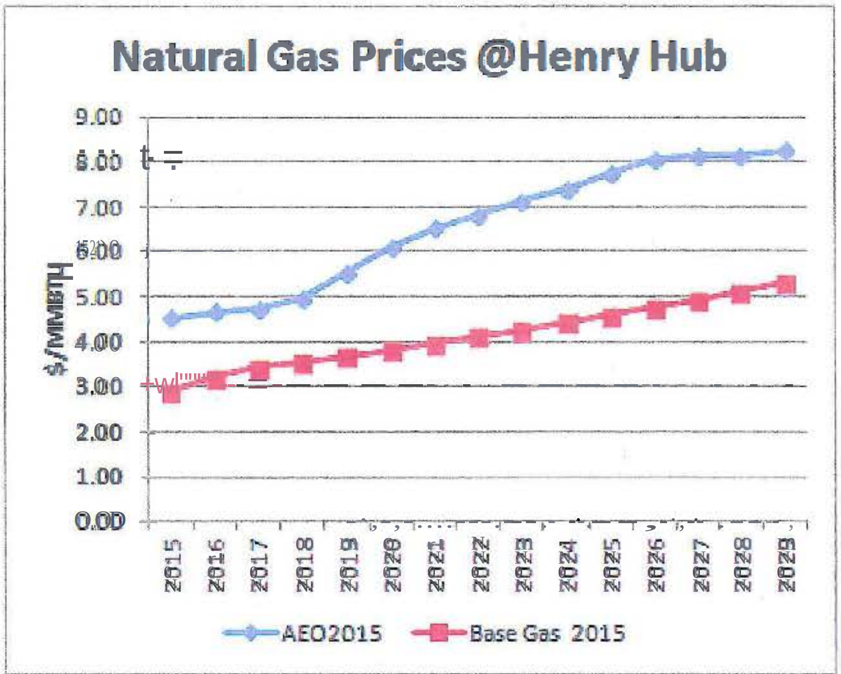
The SCE&G natural gas price forecast is the lowest of the forecasts reported on Charts B and G. It is the forecast used in these studies as the base case value for future gas prices. Charts B and C compare SCE&G baseline natural gas price forecast to the EIA's forecast that was provided in their 2015 Annual Energy Outlook.

CHART B

	Natural Gas Price Forecasts @Henry Hub ($ per MMBTU)						
	2016	2017	2018	2019	2020	2030	2035
SCEG Baseline	3.22	3.44	3.56	3.70	3.83	5.51	6.60
EIA 2015 Forecast	4.67	4.73	4.96	5.52	6.11	8.34	10.25

Chart C graph compares SCE&G's baseline forecast to that of the EIA.

CHART C



Social Cost of Carbon

In 2009, the Obama Administration convened a group of federal agencies to establish a social cost for CO_2 to be used in future rulemaking by federal agencies. In 2010, this interagency committee published its first social cost of carbon ("SCC"), a monetized value associated with the cost of emitting a ton of CO_2. In 2013 the interagency working group published an updated report with new estimates of the social cost of carbon. [1] Following is a copy of a table from the government's report on SCC estimates summarizing their results:

[1] Whitehouse Report: "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" https://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf

Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate	5.0%	3.0%	2.5%	3.0%
Year	Avg	Avg	Avg	95th
2010	11	33	52	90
2015	12	38	58	109
2020	12	43	65	129
2025	14	48	70	144
2030	16	52	76	159
2035	19	57	81	176
2040	21	62	87	192
2045	24	66	92	206
2050	27	71	98	221

The cost of carbon emissions shown in the above table are stated in 2007$. The following table restates the costs in nominal dollars assuming an inflation rate of 2% and includes the costs used in SCE&G's study.

	Social Cost of CO2 in Nominal Dollars				SCE&G's Study	
Discount Rate	5.0%	3.0%	2.5%	3.0%		
Year	Avg	Avg	Avg	95th	$15/Ton	$30/ton
2010	12	35	55	96		
2015	14	45	68	128		
2020	16	56	84	167	$15	$30
2025	20	69	100	206	$19	$38
2030	25	82	120	251	$24	$49
2035	33	99	141	306	$31	$62
2040	40	119	167	369	$40	$80
2045	51	140	195	437	$51	$102
2050	63	166	230	518	$65	$130

SCE&G's scenario of $15 per ton is very close to the lowest government estimates for SCC based on a social discount rate of 5.0%. Both of SCE&G's scenarios, the $15 and $30 scenarios, are below the SCC values recommended for government use i.e. those based on a 3.0% discount rate and are well below the high estimates based on a 2.5% social discount rate and the 95th percentile in the 3.0% discount case.

Capital Costs and Operating Costs of Natural Gas Capacity

The gas resource strategy relies on combined cycle plants for additional base load generation. As mentioned above, both the nuclear and natural gas resource strategies add simple cycle combustion turbines to meet additional capacity needs. Chart F contains the costs and heat rates assumed for these units. These inputs are based on SCE&G's ongoing monitoring of equipment and construction prices and are verified through reviews of published prices and vendor discussions. They reflect current costs to engineer, procure and construct the assets in question including land costs, pipeline connection costs, transmission costs and permitting costs.

CHART F

Gas Technology	Capacity Rating MW	Construction Cost $/KW	Heat Rate BTU/KWH	Fixed O&M Per Year	Variable O&M Per MWH
Simple Cycle	93	$740	9,169	$63,400	$1.36
Combined Cycle	614	$1,083	6,862	$8,833,000	$1.29

Miscellaneous Inputs

In this study, all carrying costs on capital investments are calculated including taxes, depreciation, insurance and cost of capital as applicable to the type of asset in question. Fixed and variable O&M are based on current estimates of turbine maintenance costs for combined cycle units. Nuclear production tax credits have been updated. Nuclear fuel costs are based on current forecasts of uranium prices and prices of new fuel assembly fabrication.

Scenario Analysis

In this study, the nuclear strategy and the natural gas resource strategies were studied under 27 different scenarios: three different natural gas prices, three different costs per ton of CO_2 emitted and three different levels of load on SCE&G's system.

a. Natural Gas Price Scenarios - The natural gas scenarios included the base line forecast of future natural gas prices as previously discussed as well as prices reflecting a 50% and 100% increase in the base line forecast. These three gas scenarios quantify the sensitivity of the analysis to variable natural gas prices. Chart G shows the natural gas price for each scenario for several years in the forecast period, as well as EIA's projection for reference.

CHART G

Natural Gas Price Forecasts @Henry Hub ($ per MMBTU)							
	2016	2017	2018	2019	2020	2030	2035
SCEG Baseline	3.22	3.44	3.56	3.70	3.83	5.51	6.60
50% Higher Scenario	4.83	5.16	5.35	5.54	5.75	8.26	9.90
100% Higher Scenario	6.64	6.88	7.13	7.39	7.67	11.02	13.20
EIA 2015 Forecast	4.67	4.73	4.96	5.52	6.11	8.34	10.25

The EIA forecast of natural gas prices approximates the 50% higher scenario.

b. CO_2 Cost Scenarios – In light of current national environmental policies, it is clear that there will be a cost associated with the emissions of CO_2 in the future. The EPA's Clean Power Plan, which is expected to be finalized this summer, puts a cap on the level of emissions.

It remains to be seen whether or not a fully fledged cap and trade system will ultimately develop. In any case utilities will incur costs to lower their emissions of CO_2, certainly in the uneconomic dispatch of their generation fleets and probably through the early retirement of coal units and new investment in replacement capacity. In the present study there were three CO_2 cost scenarios used: $0, $15 and $30 per ton beginning in 2020 and escalating at 5%.

CO_2 costs at $0 per ton are not a realistic expectation for the long term. However, the $0 per ton CO_2 scenario provides a useful lower bound to test the sensitivity of the study to this input. The scenarios with $15 and $30 per ton will provide a sensitivity to the emissions cost. Both numbers are below the Social Cost of Carbon set by the government as mentioned previously.

c. Load Forecasts Scenarios - Three scenarios representing variations of the base case load forecast scenarios were modeled. They included the base case forecast and load forecast scenarios where the load was 5% higher and 5% lower than the base case. These higher and lower load scenarios were modeled to test the sensitivity of the analysis to variability in load due to factors such as increased economic activity or increased rates of energy conservation The 5% plus or minus load scenarios provide for a reasonable assessment of possible variation in load on the system.

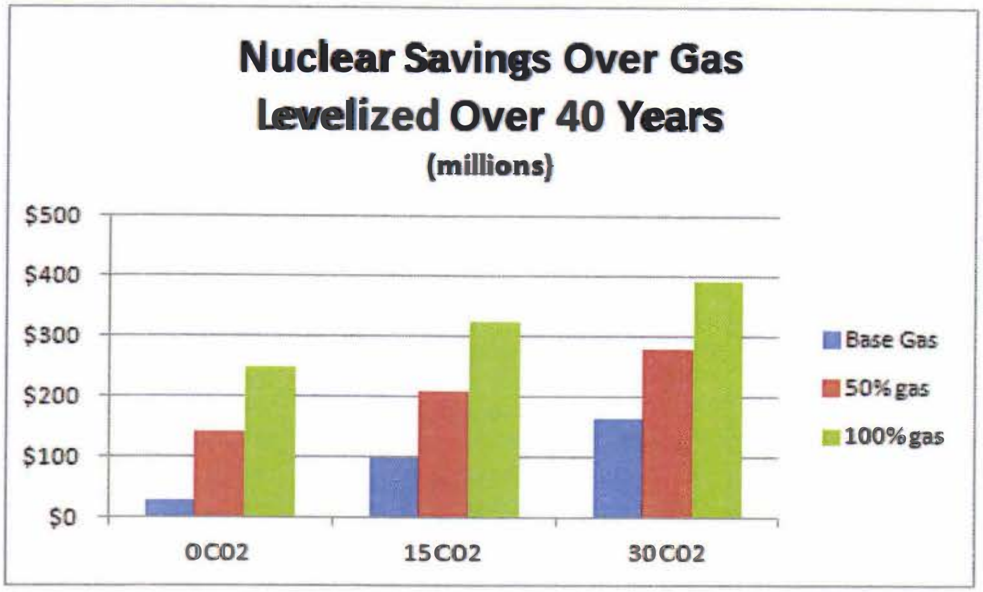
Dispatch Modeling

For each of the 54 combinations of 27 scenarios and 2 generation strategies, a simulation of the generation system dispatch was run using the PROSYM dispatch model. The PROSYM model is licensed from Ventyx and is widely used in the utility industry. This model determined how each generation resource on the system would be dispatched under each scenario over the 40 year planning horizon. Modeling the dispatch of the system using the PROSYM model produced both fuel cost and variable O&M costs for each scenario for each of the 40 years of the planning period. These fuel costs and variable O&M costs generated by the PROSYM model were then combined with the capital costs and other fixed costs for each scenario to determine a levelized annual cost for each of the 27 scenarios over the 40 year planning horizon.

Scenario Results

The results of the modeling are set forth below in Chart H. This chart shows the savings from continuing to construct the Units based on three sets of assumptions as to future gas prices, and based on CO_2 costs of $0, $15 and $30 evaluated against SCE&G's base case scenario for future load. SCE&G believes that the most reasonable scenario for planning purposes is the scenario that models a $30 CO_2 cost and gas prices that are 50% higher than the current SCE&G gas forecast. That analysis shows that the nuclear strategy is less costly than gas by a levelized amount of $278 million per year for 40 years.

CHART H



The numerical results of the scenarios shown in Chart H are set forth in Chart I below:

CHART I
Base Load Scenario

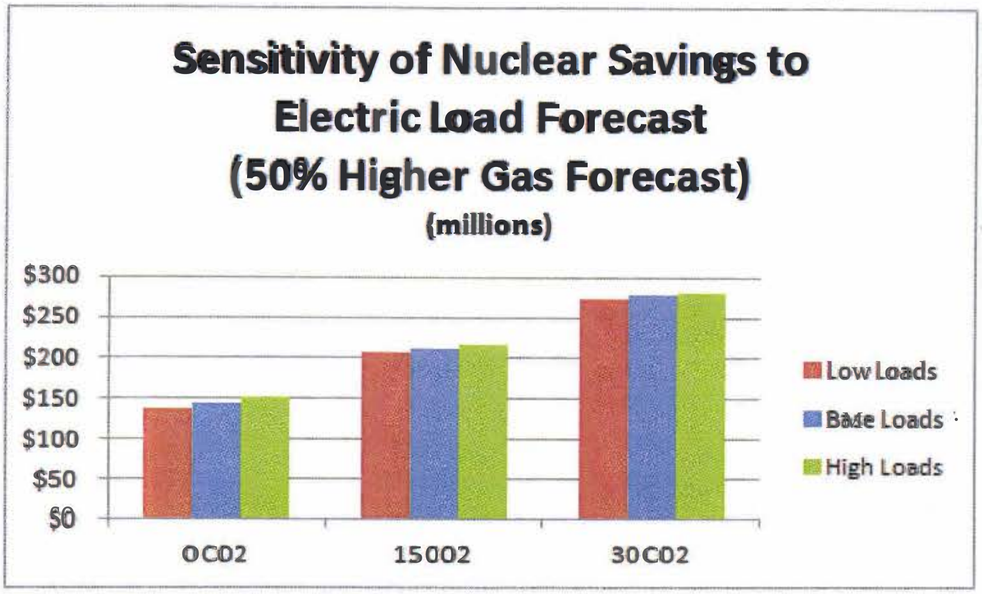
Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years ($MM)			
	Base Gas	**50% Higher Gas**	**100% Higher Gas**
$0 CO2 Price	**$28**	**$144**	**$248**
$15 CO2 Price	**$97**	**$210**	**$326**
$30 CO2 Price	**$166**	**$278**	**$392**

This Chart highlights several critical points. First, completing the nuclear construction program is more economical than switching to a gas resource strategy across all scenarios modeled. In not one case is gas less costly than nuclear. The lowest level of nuclear advantage is a levelized annual advantage of approximately $28 million per year. This occurs using base gas price assumptions and CO_2 prices at $0 per ton. In the 2008 Studies, the $0 per ton CO_2 scenario with low gas prices resulted in nuclear being more costly than gas by $44 million.

In this series of scenarios, the nuclear strategy had the highest cost advantage over gas in the 100% Higher Gas scenario with a $30 per ton CO_2 price. In that scenario, the nuclear strategy was more cost effective than the gas resource strategy by a levelized amount of $392 million per year. As mentioned above, the scenario with the set of assumptions that SCE&G believes to be most reasonable for planning purposes is 50% higher gas prices with $30 per ton CO_2 where nuclear has a cost advantage over gas of $278 million per year.

Studies were run with different assumptions as to future levels of system load to determine whether the studies' results were sensitive to changes in future electric load forecasts. Chart J shows results calculated using the base load forecast side by side with result calculated using load forecasts that have been increased by 5% and decreased by 5%. The chart shows very little variability in results based on changes in the load forecast.

CHART J



The scenario results reported on Chart J are for the 50% Higher Gas scenario. The Base Gas and 100% Higher Gas scenarios were modeled in the same way. The resulting charts are attached as Appendix 2 and the underlying data is attached as Appendix 3. They show a similar alignment of results. Collectively, these charts show that the cost advantage of the nuclear strategy over the natural gas resource strategy is consistent whether electric loads are greater or less than anticipated in the future.

There are several other inferences that can be drawn from these results of testing the nuclear and the gas resource strategies across these 27 scenarios. First, the advantage that the nuclear strategy has over the gas strategy is not dependent on load growth forecasts. Forecasts for load growth are currently very low. But even if the current load growth projections turn out to be high because of DSM, energy efficiency or distributed or alternative generation, the nuclear advantage is not materially reduced.

Second, the study shows that the comparative economics of the nuclear and natural gas resource strategies swing widely based on gas price forecasts and future CO_2 cost assumptions. This shows that the economics of the gas resource strategy are very sensitive to swings in natural gas prices and CO_2 costs. This confirms that a resource strategy dependent of natural gas generation significantly increases SCE&G's exposure to fossil-fuel volatility and environmental cost increases.

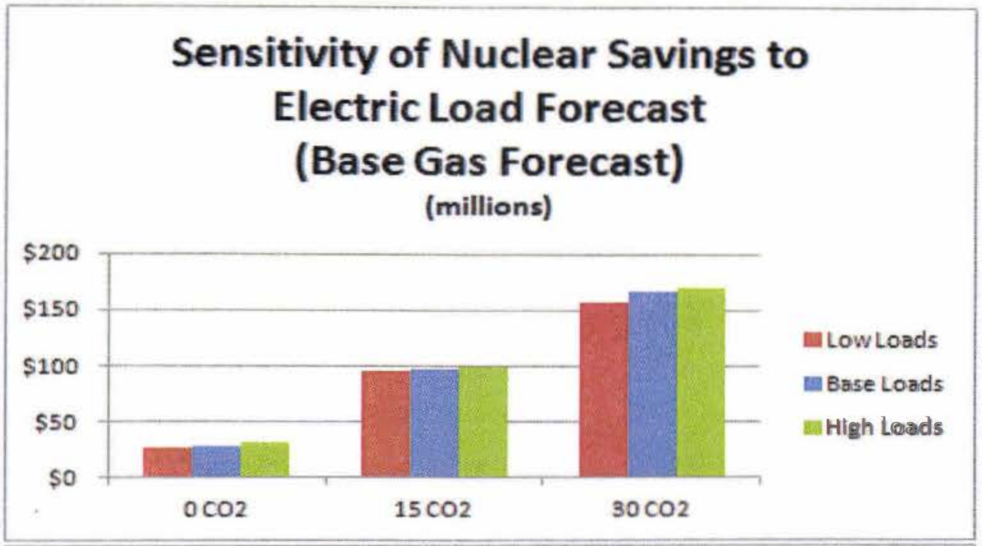
Conclusion

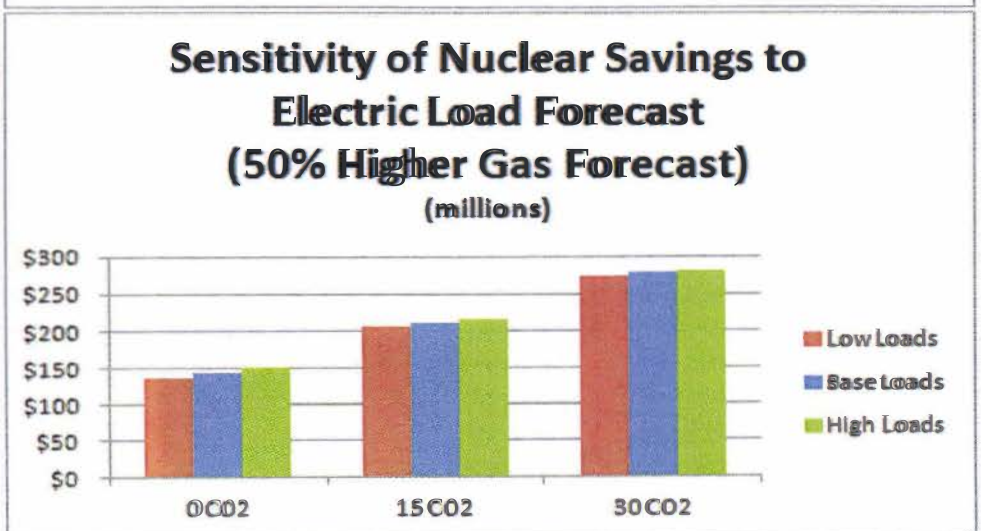
The results of this study demonstrate through the use of a full system dispatch model, run over a 40 year planning cycle, and using updated information on relevant parameters that the nuclear strategy remains the strategy best able to provide favorable results over a broad range of future operating conditions. The most reasonable estimate of the cost advantage of completing the Units is $278 million per year for 40 years.

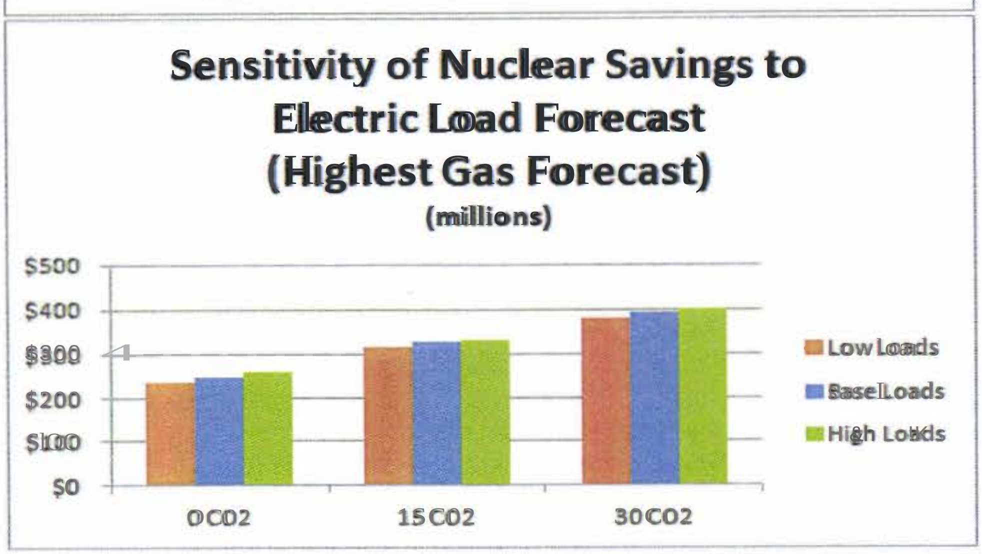
SCE&G Forecast of Summer Loads and Resources • Basecase Nuclear Resource Plan (MW)

	YEAR	2016	2016	2017	2018	2019	2020	2021	2022	2023	2024	2026	2026	2027	2028	2029
Load Forecast																
1	Baseline Trend	5006	5089	5212	5341	5467	5595	5719	5833	5950	6059	6162	6268	6366	6460	6559
2	EE Impact	-3	-8	-22	-36	-50	-62	-74	-86	-98	-111	-123	-136	-149	-163	-176
3	Gross Territorial Peak	5003	5081	5190	5305	5417	5533	5645	5747	5852	5948	6039	6132	6217	6297	6383
4	Demand Response	-256	-259	-265	-272	-275	-277	-280	-283	-286	-289	-292	-295	-298	-301	-304
5	Net Territorial Peak	4747	4822	4925	5033	5142	5256	5365	5464	5566	5659	5747	5837	5919	5996	6079
System Capacity																
6	Existing	5282	5289	5308	5314	5320	5940	6215	6215	6308	6401	6494	6587	6680	6773	6866
	Additions:															
7	Solar Plant (2% DER)	7	19	6	6	6	6									
8	Peaking/Intermediate								93	93	93	93	93	93	93	93
9	Baseload					614	614									
10	Retirements						-345									
11	Total System Capacity	5289	5308	5314	5320	5940	6215	6215	6308	6401	6494	6587	6680	6773	6866	6959
12	Firm Annual Purchase	300	300	300	425											
13	Total Production Capability	5589	5608	5614	5745	5940	6215	6215	6308	6401	6494	6587	6680	6773	6866	6959
Reserves																
14	Margin (L13-L5)	842	786	689	712	798	959	850	844	835	835	840	843	854	870	880
15	% Reserve Margin (L14/L5)	17.7%	16.3%	14.0%	14.1%	15.5%	18.2%	15.8%	15.4%	15.0%	14.8%	14.6%	14.4%	14.4%	14.5%	14.5%

Sensitivity of Nuclear Savings to Electric Load Forecast







Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years

(\$MM)

Base Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO2 Price	\$28	\$144	\$248
\$15 CO2 Price	\$97	\$210	\$326
\$30 CO2 Price	\$166	\$278	\$392

High Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO2 Price	\$30	\$150	\$260
\$15 CO2 Price	\$98	\$215	\$335
\$30 CO2 Price	\$170	\$281	\$400

Low Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO2 Price	\$26	\$137	\$233
\$15 CO2 Price	\$95	\$205	\$315
\$30 CO2 Price	\$157	\$273	\$382

Corrected Version

DIRECT TESTIMONY
OF
JOSEPH M. LYNCH
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2015-103-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION WITH SOUTH CAROLINA ELECTRIC & GAS COMPANY ("SCE&G" OR "COMPANY").

A. My name is Joseph M. Lynch and my business address is 220 Operation Way, Cayce, South Carolina. My current position with the Company is Manager of Resource Planning.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from St. Francis College in Brooklyn, New York, with a Bachelor of Science degree in mathematics. From the University of South Carolina, I received a Master of Arts degree in mathematics, an MBA, and a Ph.D. in management science and finance. I was employed by SCE&G as a Senior Budget Analyst in 1977 to develop econometric models to forecast electric sales and revenue. In 1980, I was promoted to Supervisor of the Load Research

Department. In 1985, I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and, in 1991, I was promoted to my current position of Manager of Resource Planning.

Q. WHAT ARE YOUR CURRENT DUTIES AS MANAGER OF RESOURCE PLANNING?

A. As Manager of Resource Planning, I am responsible for producing SCE&G's forecast of energy, peak demand, and revenue; for developing the Company's generation expansion plans; and for overseeing the Company's load research program.

Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION") PREVIOUSLY?

A. Yes. I have previously testified on a number of occasions before this Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the results of a study comparing the impact on costs to customers of two strategies: The first is to complete the construction of the V.C. Summer Units 2 and 3 (the "Units"). The second is to stop construction and replace the Units with two combined cycle gas plants of the same size. The study is attached to my testimony as Exhibit No. __ (JML-1).

Q. PLEASE DESCRIBE THE METHODOLOGY USED IN THE STUDY.

A. The study uses the same methodology and structure as the similar study presented to the Commission in 2012 in Docket No. 2012-203-E. The study is based on modeling techniques that are widely accepted in the utility industry to determine the relative cost and value of alternative approaches to meeting customers' electricity needs. The models used in the study include information about system loads, load shapes (the number of hours each year that specific load levels are reached), the available units, the ramp rates of units (the speed at which units can be brought to various levels of production), the availability factors of the units (how often units are off-line or have mechanical or environmental limits on their generating capacity), the fuel costs of units (including environmental costs of burning fuel and disposing of ash or other fuel wastes), the fuel efficiency of units (how much fuel cost is incurred per megawatt (MW) of energy produced), and the capital and operating costs of any new units including things like depreciation, abandonment costs, salvage cost, production tax credits and other capital related costs or benefits. Each scenario includes a different set of assumptions about one or more variables. In this case, the models dispatched the system year-by-year for 40 years to determine the relative cost to customers under each scenario considered.

Q. WHAT SCENARIOS WERE MODELED?

A. The two alternatives -completing construction of the Units compared to replacing them with combined cycle gas plants- were analyzed under twenty-seven

(27) scenarios reflecting different assumptions concerning natural gas prices, CO_2 emissions costs and future load growth on our system.

Q. WHAT NATURAL GAS PRICE SCENARIOS WERE MODELED?

A. The three natural gas price scenarios were the Company's base case forecast of future natural gas prices, a 50% higher gas price and a 100% higher gas price forecast.

Q. WHY WERE THESE THREE NATURAL GAS PRICE SCENARIOS CHOSEN?

A. The base case is a forecast that the Company compiles using reported NYMEX gas contracts. Future prices for contracts for three years are used. Beginning in year four, the forecast escalates the NYMEX price using inflation rate forecasts provided by our economic forecasting firm IHS Global Insights.

SCE&G uses the base case forecast as a starting point in modeling because it is simple, objective and less subject to bias from subjective considerations. But this is also a limitation. The base case gas price may ignore important factors that require subjective judgment and are not reflected in current NYMEX prices or in inflation forecasts. In short, fossil fuel prices, especially natural gas prices, are notoriously difficult to forecast with confidence. For this reason, SCE&G usually conducts sensitivity analyses particularly with respect to future natural gas prices. Therefore in addition to the base case gas price forecast, two other price scenarios were developed: one with 50% higher prices than base case and a second with

100% higher prices. Higher gas prices seem very reasonable when you consider ongoing and future changes that will put upward pressure on natural gas prices. The most obvious of these changes include: 1) significantly increased demand in the power generation sector caused by the retirement of coal plants due to EPA's Mercury and Air Toxics Standards ("Mats")regulations and the Clean Power Plan as well as the practical inability to add coal capacity in the future in light of environmental regulations; 2) the opening of the domestic gas market to higher world prices through LNG exportation; 3) the increasing regulatory scrutiny of "fracking" from an environmental point of view which will tend to increase the cost of production and reduce the supply of gas; and 4) the inescapable fact that burning natural gas emits CO_2 into the atmosphere and that the gas industry will likely come under environmental regulations similar to those crippling the coal industry. The Energy Information Administration in their 2015 Annual Energy Outlook provides another scenario of forecasted natural gas prices and their forecast is shown in the study as a point of comparison. The EIA forecast approximates the 50% higher gas price forecast.

Q. WHAT CO_2 PRICE SCENARIOS WERE MODELED?

A. The three variations of CO_2 emission costs were $0, $15 and $30 per ton starting in 2020 and escalating at 5% per year.

SCE&G does not believe that there is much possibility of a $0 per ton future. The scenarios modeled at $0 per ton are not considered meaningful scenarios in themselves. They are included as a base line to show the impact of the CO_2 component on costs.

The EPA has not finalized its Clean Power Plan. But no matter what form the final regulations take, SCE&G will need to reduce its emissions of CO_2 substantially. The cost of doing so will be significant. The study uses $15 and $30 per ton to show the impact of CO_2 compliance on the generation plan. The $30 dollars per ton estimate is the more probable of the two although the actual cost of CO_2 compliance is likely to be higher. For example, under Executive Order 12866, the federal government has established values for measuring the social cost of carbon in assessing the environmental impacts of federal action. The recommended value is $56 per ton in 2020. The $30 per ton cost is probably low but is still sufficient to show the impact of CO_2 costs on the value of the alternatives considered by the report.

Q. WHAT LOAD GROWTH SCENARIOS WERE MODELED?

A. The three load levels considered were the Company's base case load forecast and then a low and high forecast which adjusted the forecasted load plus and minus 5%.

Q. WHAT IS THE VALUE OF INCLUDING THESE DIFFERENT LOAD GROWTH SCENARIOS?

A. The load growth scenarios show that varying load up or down 5% does not affect the value of the scenarios very much at all. This is relevant because including more distributed energy resources (solar generation) or more energy efficiency gains has the same effect as reducing load growth. Our base case forecast already includes the impact of currently mandated distributed energy resources and currently planned energy efficiency investments. There may be other important reasons to increase investment in these resources. But the study shows that increasing these resources by a substantial amount does not change the value of the nuclear Units to customers in a meaningful way.

Q. WHAT WERE THE RESULTS OF THE STUDY?

A. The study shows that in all 27 scenarios, including base gas price and $0 carbon costs, the effect of cancelling the Units and switching to natural gas generation increases the costs to our customers by a significant amount. The most reasonable scenario is gas prices at base cost plus 50% and CO_2 emissions at $30 per ton. In that scenario, cancelling the Units and switching to natural gas would increase the cost to SCE&G's customers for electric service by $278 million per year on average over the 40 year planning horizon.

Q. HAVE YOU ANALYZED THE SENSITIVITY OF RESULTS TO AN INCREASE IN THE COST TO COMPLETE THE NUCLEAR UNITS?

A. Exhibit No. ___ (JML-2) answers the question: Where we stand today, how much would the nuclear construction costs have to increase to achieve a breakeven point between completing the nuclear project and cancelling it? This study already recognizes the updates to capital costs that are before the Commission in this proceeding. Thus, the total cost of completing the nuclear plants is assumed to be about $6.8 billion. Exhibit No. ___ (JML-2) shows how much this cost would have to increase to make the incremental revenue requirements of cancelling the nuclear project equal to those of completing it. The most reasonable scenario reflects base gas cost plus 50% and $30 per ton CO_2. In that scenario, the future capital costs of the Units would have to increase by about $3.1 billion above current forecasts to overcome the benefit of $278 million per year from completing the Units at their current cost. Or to put it another way, from where we are today, the total construction cost would have to increase from $6.8 billion to about $9.9 billion to reach the breakeven point between the alternatives.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit No. ________(JML-2)

Increase in Capital Costs of Nuclear Strategy Needed for Breakeven with Gas Strategy Based on Present Worth of Incremental Revenue Requirements Over 40 Years

($MM)

Base Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	$314	$1,602	$2,762
$15 CO_2 Price	$1,084	$2,341	$3,632
$30 CO_2 Price	$1,854	$3,102	$4,366

High Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	$336	$1,670	$2,893
$15 CO_2 Price	$1,096	$2,395	$3,731
$30 CO_2 Price	$1,897	$3,135	$4,460

Low Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	$291	$1,525	$2,598
$15 CO_2 Price	$1,062	$2,282	$3,514
$30 CO_2 Price	$1,749	$3,047	$4,259

Exhibit_(JML-7)

Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy

July 1, 2016

SCE&G®
A SCANA COMPANY

Introduction

The purpose of this study is to determine if abandoning SCE&G's ongoing nuclear construction program and pursuing a natural gas generation strategy for base load generation needs would benefit retail customers in terms of long-run revenue requirements. SCE&G's management directed the Resource Planning Department to use current data to prepare generation cost studies comparable to those performed in 2008 that supported the original decision to construct the two nuclear units (the "Units").

SCE&G has undertaken this exercise expressly reaffirming its position that no single analysis of comparative costs underlies its choice of nuclear generation over gas-fired generation alternatives. The goal of base load generation planning is to create a diverse and flexible portfolio of generation units that can perform effectively in multiple sets of conditions over 40 years or more. No single study or series of studies is an effective substitute for informed business judgment exercised with this goal in mind.

This study calculates the incremental revenue requirements on a comparative basis for two strategies. The first is the base case which involves completing the two nuclear units which are presently under construction and scheduled to go into service in 2019 and 2020. When completed, the Units together will provide SCE&G with 1,229 MW. The second strategy is the natural gas resource strategy in which the Units are cancelled at the effective date of December 31, 2016. The Units are replaced by two combined-cycle units rated at 614 MWs each which come into service in 2019 and 2020 also.

The principal components of the study and conclusion are set forth below. The inputs to the study have been updated to reflect the most current values available.

Load Forecast and Resource Plans

To compute the revenue requirements of the two strategies over a 40-year planning horizon, the study relies on the load forecast data that were reported in summary form in SCE&G's 2016 Integrated Resource Plan. These load forecasts are updated versions of those that were used in the 2008 planning studies (the "2008 Studies") on which the original Base Load Review Act ("BLRA") order was based. Both the nuclear and gas resource strategies are measured against identical load forecasts.

Appendix 1 shows the forecast and the base case scenario resource plan. Both the nuclear capacity and the natural gas combined-cycle capacity are shown on the alternative versions of the resource plan as "base load" capacity entered on line 9 in the table shown in Appendix 1. As was the case with the 2008 Studies, the resource plans for each of the two strategies assumed that, after the base load capacity was added, additional simple-cycle natural gas-fired generation was added to meet subsequent load growth. Comparable amounts of simple-cycle generation with comparable capital cost and operating costs were added under each strategy.

Abandoning Nuclear Construction

As of December 31, 2016, SCE&G expects to have spent $4.607 billion on construction of the Units. If SCE&G were to decide to cancel the nuclear construction project, it would be subject to contractual cancellation charges, site decommissioning and stabilization expenses and other abandonment expenses in addition to the $4.607 billion that would already have been spent. SCE&G's best assessment of the amount of those cancellation expenses would be $262 million for a cancellation effective December 31, 2016. This is the cost on a 100% basis (i.e., including Santee Cooper's 45% share in expenses).

Upon cancellation of the project, SCE&G could scrap, sell or salvage certain materials, equipment and work in progress and could use the proceeds to off-set some part of the abandonment expenses. A large component of the spending to date, however, has been for site work, construction of roads, building and bridges on site, the hiring and training of personnel, design and procurement work, and other activities that do not produce salvageable materials. SCE&G estimates that of the amounts spent to date, the salvage value of materials, equipment, and work in progress would be approximately $318 million on a 100% basis. This $318 million would be netted against the gross cancellation cost of $262 million to produce an estimate of the net cancellation benefit, not considering the $4.607 billion already spent, of $56 million, again on a 100% basis. SCE&G's customers would receive the benefit of 55% of this or $31 million.

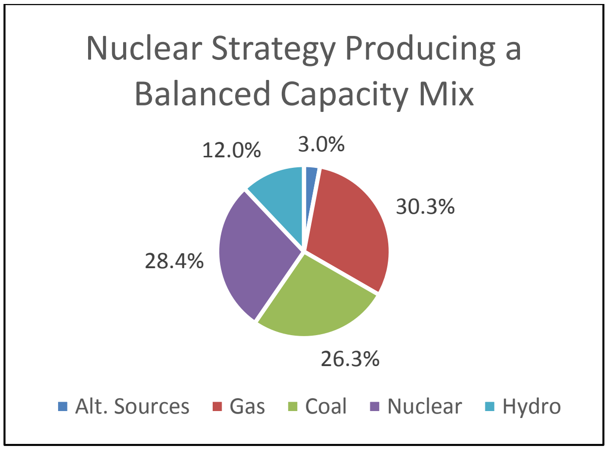
Thus, subtracting the net cancellation gain of $31 million from the $4.607 billion spent as of December 31, 2016, produces a total abandonment cost of $4.576 billion.

The model used for comparing the costs of these two strategies computes a levelized cost for capital invested that includes all relevant parameters given the nature of the asset involved. This combination of costs spent to date and additional cost to abandon the project represent a cost that must be borne by the gas resource strategy.

Benefit of a Balanced Capacity Portfolio

A significant advantage of continuing construction of the two nuclear units is that once added to SCE&G's generation fleet, the Units will produce a well-balanced capacity portfolio. The following charts show the percent distribution of capacity under a plan of continuing nuclear construction and the alternative of replacing it with natural gas-fired capacity.

CHART A



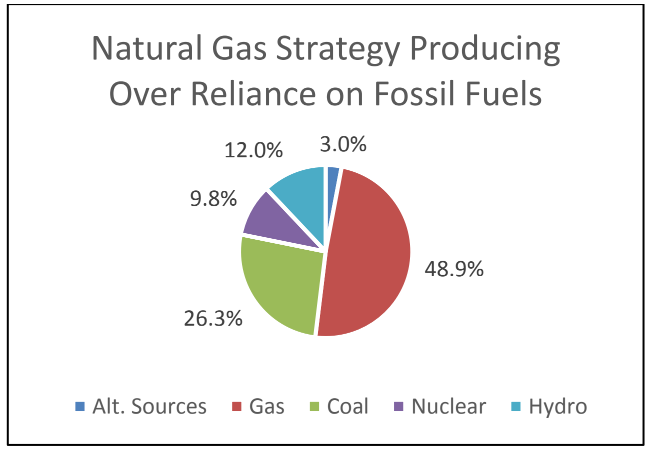


Chart A shows that the Natural Gas Strategy produces a generation system that in 2021 relies on fossil fuels for 75.2% of its generating capacity. The Nuclear Strategy creates a more balanced portfolio. Such a portfolio better protects customers from unexpectedly high costs in any one fuel source while allowing the utility to take advantage of opportunities in others.

Price of Natural Gas

Chart B shows two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration ("EIA") natural gas forecast reported in their 2016 Annual Energy Outlook ("AEO"). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor projected by the economic forecasting firm IHS Global Insight, Inc. to forecast prices beyond three years in the future. This is a methodology that SCE&G has used for a number of years to produce gas forecasts for planning studies. The value of this methodology is that it is simple and objective. However, because all forecasts of future gas prices are subject to error, SCE&G typically tests the results of these studies done using these forecasts through sensitivity analyses that model variations in gas prices.

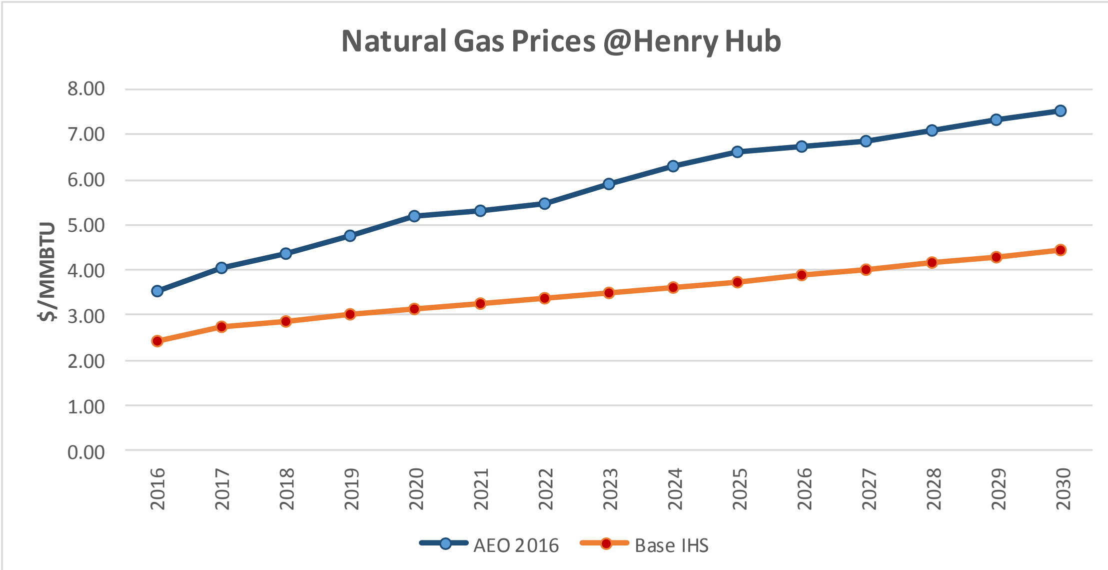
The SCE&G natural gas price forecast is the lowest of the forecasts reported on Charts B and G. It is the forecast used in these studies as the base case value for future gas prices. Charts B and C compare SCE&G baseline natural gas price forecast to the EIA's forecast that was provided in their 2016 AEO.

CHART B

	Natural Gas Price Forecasts @Henry Hub ($ per MMBTU)						
	2016	**2017**	**2018**	**2019**	**2020**	**2030**	**2035**
SCEG Baseline	2.41	2.74	2.88	2.98	3.08	4.32	5.11
EIA 2016 Forecast	3.53	4.04	4.37	4.74	5.18	7.54	8.13

Chart C graph compares SCE&G's baseline forecast to that of the EIA.

CHART C



Social Cost of Carbon

In 2009, the Obama Administration convened a group of federal agencies to establish a social cost for carbon dioxide ("CO_2") to be used in future rulemaking by federal agencies. In 2010, this interagency committee published its first social cost of carbon ("SCC"), a monetized value associated with the cost of emitting a ton of CO_2. In 2013, the interagency working group published an updated report with new estimates of the social cost of carbon.[1] Following is a copy of a table from the government's report on SCC estimates summarizing their results:

[CHART D IS ON FOLLOWING PAGE]

[1] Whitehouse Report: "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" https://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf

CHART D

Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate	5.0%	3.0%	2.5%	3.0%
Year	Avg	Avg	Avg	95th
2010	11	33	52	90
2015	12	38	58	109
2020	12	43	65	129
2025	14	48	70	144
2030	16	52	76	159
2035	19	57	81	176
2040	21	62	87	192
2045	24	66	92	206
2050	27	71	98	221

The cost of carbon emissions shown in the above table are stated in 2007 dollars. The following table restates the costs in nominal dollars assuming an inflation rate of 2% and includes the costs used in SCE&G's study.

CHART E

	Social Cost of CO2 in Nominal Dollars					SCE&G's Study	
Discount Rate	5.0%	3.0%	2.5%	3.0%			
Year	Avg	Avg	Avg	95th		$15/Ton	$30/ton
2010	12	35	55	96			
2015	14	45	68	128			
2020	16	56	84	167			
2025	20	69	100	206		$15	$30
2030	25	82	120	251		$19	$38
2035	33	99	141	306		$24	$49
2040	40	119	167	369		$31	$62
2045	51	140	195	437		$40	$80
2050	63	166	230	518		$51	$102

SCE&G's scenario of $15 per ton is very close to the lowest government estimates for SCC based on a social discount rate of 5.0%. Both of SCE&G's scenarios, the $15 and $30 scenarios, are below the SCC values recommended for government use, *i.e.*, those based on a 3.0% discount rate and are well below the high estimates based on a 2.5% social discount rate and the 95th percentile in the 3.0% discount case.

The Clean Power Plan

In August 2015 the Environmental Protection Agency ("EPA") published its Clean Power Plan under which the emissions of CO_2 by certain fossil generating plants would be regulated. The EPA established emission targets for each state covered by regulations issued under Section 111(d) of the Federal Clean Air Act and has proposed various pathways for each state to comply with those targets. Those pathways include a "rate-based" compliance plan, wherein each electric generating unit ("EGU") would be required to meet an emission rate target.

Alternatively, a state may select a "mass-based" compliance plan, in which an EGU would be allocated a CO_2 emission cap. In both the rate and mass-based plans, EGUs would have the opportunity to trade credits or allocations to assist in meeting those targets. Under a rate-based compliance plan the new nuclear units would count towards compliance and would generate sufficient emission rate credits that SCE&G would not be required to incur any additional CO_2 compliance costs under the Clean Power Plan. On the other hand, if the new nuclear units are not built then SCE&G would be subject to a CO_2 emissions limit and incur costs to comply. In this study then it was assumed under the new nuclear scenario, SCE&G's CO_2 costs would be $0 while under the natural gas scenario, the CO_2 costs would be either $0, $15, or $30 per ton.[2]

Capital Costs and Operating Costs of Natural Gas Capacity

The gas resource strategy relies on combined-cycle plants for additional base load generation. As mentioned above, both the nuclear and natural gas resource strategies add simple-cycle combustion turbines as required to meet additional capacity needs. Chart F contains the costs and heat rates assumed for these units in 2016 dollars. These inputs are based on SCE&G's ongoing monitoring of equipment and construction prices and are verified through reviews of published prices and vendor discussions. They reflect current costs to engineer, procure, and construct the assets in question.

CHART F

Gas Technology	Capacity Rating MW	Construction Cost $/KW	Heat Rate BTU/KWH	Fixed O&M Per Year	Variable O&M Per MWH
Simple-Cycle	93	$754	9,169	$708,690	$1.36
Combined-Cycle	614	$1,105	6,862	$9,009,299	$1.29

Miscellaneous Inputs

In this study, all carrying costs on capital investments are calculated including taxes, depreciation, insurance, and cost of capital as applicable to the type of asset in question. Fixed and variable O&M include current estimates of turbine maintenance costs for combined-cycle units. Nuclear production tax credits have been updated. Nuclear fuel costs are based on current forecasts of uranium prices and prices of new fuel assembly fabrication.

Scenario Analysis

In this study, the nuclear strategy and the natural gas resource strategies were studied under 27 different scenarios: three different natural gas prices, three different costs per ton of CO_2 emitted, and three different levels of load on SCE&G's system.

a. <u>Natural Gas Price Scenarios</u> - The natural gas scenarios included the base line forecast of future natural gas prices as previously discussed as well as prices reflecting a 50%

[2] On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the United States Court of Appeals for the D.C. Circuit.

and 100% increase in the base line forecast. These three gas scenarios quantify the sensitivity of the analysis to variable natural gas prices. Chart G shows the natural gas price for each scenario for several years in the forecast period, as well as EIA's projection for reference.

CHART G

Natural Gas Price Forecasts @Henry Hub ($ per MMBTU)							
	2016	**2017**	**2018**	**2019**	**2020**	**2030**	**2035**
SCEG Baseline	2.41	2.74	2.88	2.98	3.08	4.32	5.11
50% Higher Scenario	3.61	4.11	4.32	4.48	4.62	6.47	7.66
100% Higher Scenario	4.81	5.49	5.76	5.97	6.16	8.63	10.22
EIA 2016 Forecast	3.53	4.04	4.37	4.74	5.18	7.54	8.13

b. <u>CO_2 Cost Scenarios</u> – In light of current national environmental policies, it is clear that there will be a cost associated with the emissions of CO_2 in the future. It remains to be seen whether or not a fully-fledged cap and trade system will ultimately develop. In any case utilities will incur costs to lower their emissions of CO_2, certainly in the uneconomic dispatch of their generation fleets and probably through the early retirement of coal units and new investment in replacement capacity. In the present study there were three CO_2 cost scenarios used: $0, $15, and $30 per ton beginning in 2025 and escalating at 5%.

CO_2 costs at $0 per ton are not a realistic expectation for the long term. However, the $0 per ton CO_2 scenario provides a useful lower bound to test the sensitivity of the study to this input. The scenarios with $15 and $30 per ton will provide a sensitivity to the emissions cost. Both numbers are below the SCC set by the government as mentioned previously.

c. <u>Load Forecast Scenarios</u> - Three scenarios representing variations of the base case load forecast scenarios were modeled. They included the base case forecast and load forecast scenarios where the load was 5% higher and 5% lower than the base case. These higher and lower load scenarios were modeled to test the sensitivity of the analysis to variability in load due to factors such as increased economic activity or increased rates of energy conservation. The 5% plus or minus load scenarios provide for a reasonable assessment of possible variation in load on the system.

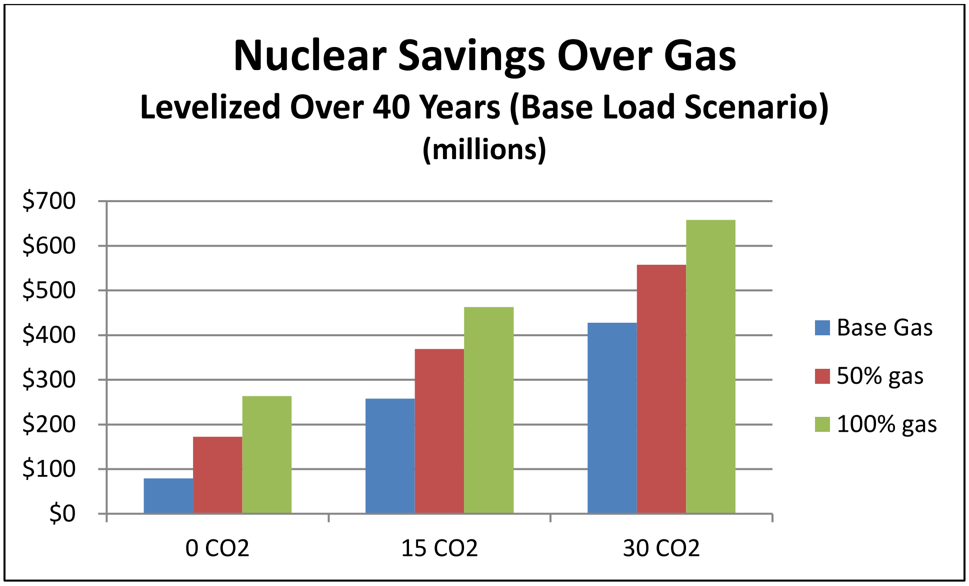
Dispatch Modeling

The results used in each of the 54 combinations of 27 scenarios and 2 generation strategies is derived from a simulation of the generation system dispatch using the PROSYM dispatch model. The PROSYM model is licensed from ABB and is widely used in the utility industry. This model determined how each generation resource on the system would be dispatched under each scenario over the 40-year planning horizon. Modeling the dispatch of the system using the PROSYM model produced both fuel cost and variable O&M costs for each scenario for each of the 40 years of the planning period. These fuel costs and variable O&M costs generated by the PROSYM model were then combined with the capital costs and other fixed costs for each scenario to determine a levelized annual cost for each of the 27 scenarios over the 40-year planning horizon.

Scenario Results

The results of the modeling are set forth below in Chart H. This chart shows the savings from continuing to construct the Units based on three sets of assumptions as to future gas prices, and based on CO_2 costs of $0, $15, and $30 evaluated against SCE&G's base case scenario for future load. SCE&G believes that the most reasonable scenario for planning purposes is the scenario that models a $15 CO_2 cost and gas prices that are 50% higher than the current SCE&G gas forecast. That analysis shows that the nuclear strategy is less costly than gas by a levelized amount of $374 million per year for 40 years.

CHART H



The numerical results of the scenarios shown in Chart H are set forth in Chart I below:

CHART I

Base Load Scenario

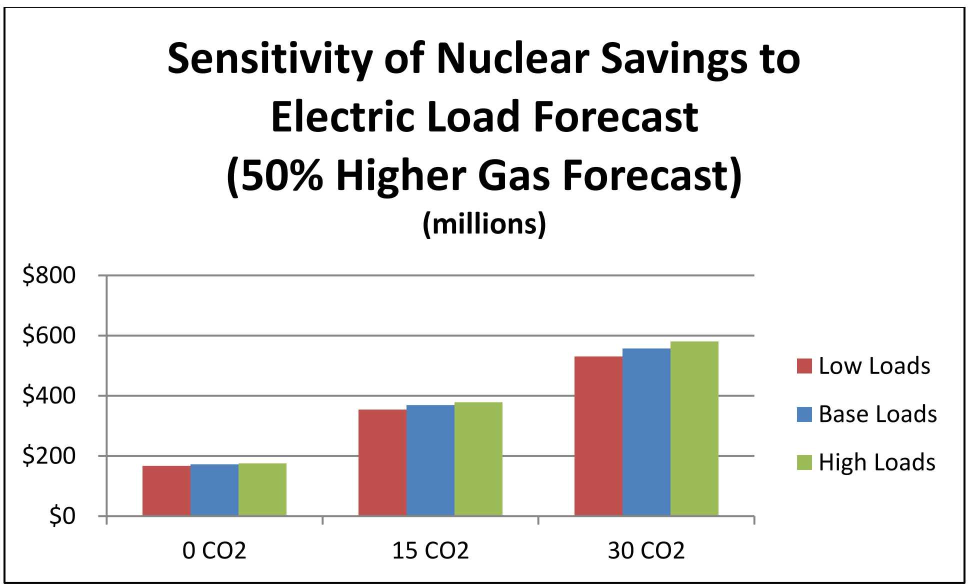
Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years (millions)			
	Base Gas	**50% Higher Gas**	**100% Higher Gas**
$0 CO2 Price	$84	$177	$269
$15 CO2 Price	$263	$374	$468
$30 CO2 Price	$433	$562	$663

This Chart highlights several critical points. First, completing the nuclear construction program is more economical than switching to a gas resource strategy across all scenarios modeled. In not one case is gas less costly than nuclear. The lowest level of nuclear advantage is a levelized annual advantage of approximately $84 million per year. This occurs using base gas price assumptions and CO_2 prices at $0 per ton. In the 2008 Studies, the $0 per ton CO_2 scenario with low gas prices resulted in nuclear being more costly than gas by $44 million.

In this series of scenarios, the nuclear strategy had the highest cost advantage over gas in the 100% Higher Gas scenario with a $30 per ton CO_2 price under the high load scenario. In that scenario, the nuclear strategy was more cost effective than the gas resource strategy by a levelized amount of $689 million per year. As mentioned above, the scenario with the set of assumptions that SCE&G believes to be most reasonable for planning purposes is 50% higher gas prices with $15 per ton CO_2 where nuclear has a cost advantage over gas of $374 million per year.

Studies were run with different assumptions as to future levels of system load to determine whether the studies' results were sensitive to changes in future electric load forecasts. Chart J shows results calculated using the base load forecast side by side with results calculated using load forecasts that have been increased by 5% and decreased by 5%. The chart shows very little variability in results based on changes in the load forecast.

CHART J



The scenario results reported on Chart J are for the 50% Higher Gas scenario. The Base Gas and 100% Higher Gas scenarios were modeled in the same way. The resulting charts are attached as Appendix 2 and the underlying data is attached as Appendix 3. They show a similar alignment of results. Collectively, these charts show that the cost advantage of the nuclear strategy over the natural gas resource strategy is consistent whether electric loads are greater or less than anticipated in the future.

There are several other inferences that can be drawn from these results of testing the nuclear and the gas resource strategies across these 27 scenarios. First, the advantage that the nuclear strategy has over the gas strategy is not dependent on load growth forecasts. Forecasts for load growth are currently very low. But even if the current load growth projections turn out to be high because of Demand Side Management, energy efficiency, or distributed or alternative generation, the nuclear advantage is not materially reduced.

Second, the study shows that the comparative economics of the nuclear and natural gas resource strategies swing widely based on gas price forecasts and future CO_2 cost assumptions. This shows that the economics of the gas resource strategy are very sensitive to swings in natural gas prices and CO_2 costs. This confirms that a resource strategy dependent of natural gas generation significantly increases SCE&G's exposure to fossil-fuel price volatility and environmental cost increases.

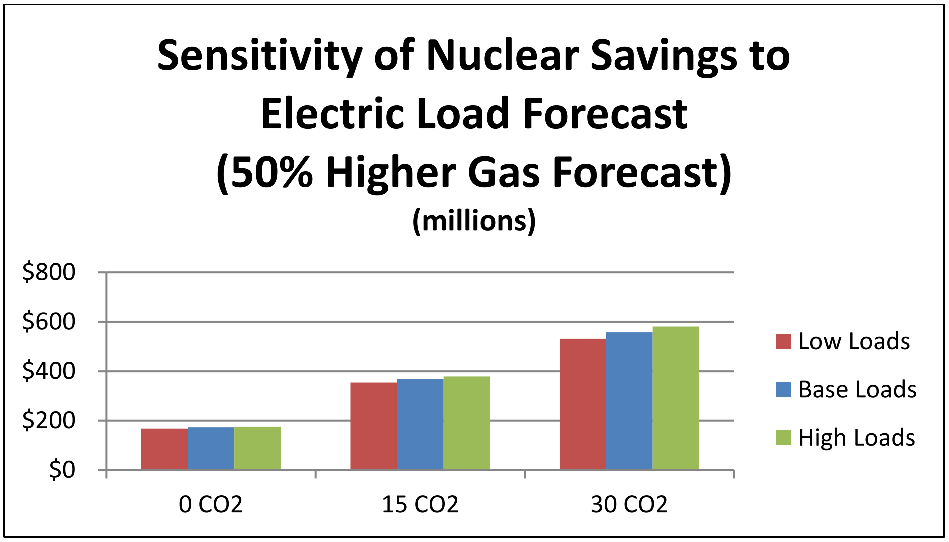
Conclusion

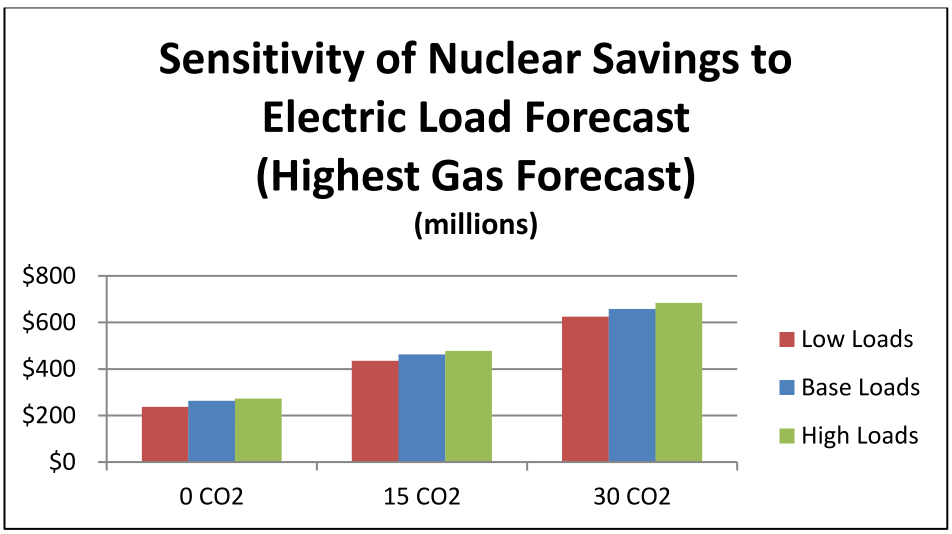
The results of this study demonstrate through the use of a full system dispatch model, run over a 40-year planning cycle, and using updated information on relevant parameters that the nuclear strategy remains the strategy best able to provide favorable results over a broad range of future operating conditions. The most reasonable estimate of the cost advantage of completing the Units is $374 million per year for 40 years.

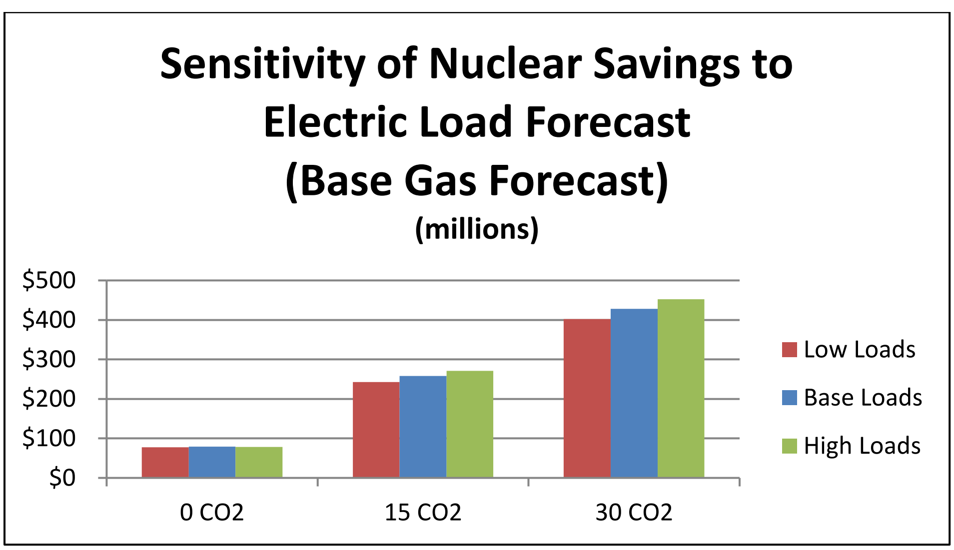
SCE&G Forecast of Summer Loads and Resources
(MW)

	YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast																
1	Baseline Trend	5031	5133	5293	5431	5582	5721	5837	5948	6047	6136	6230	6318	6403	6495	6583
2	EE Impact	-8	-13	-26	-45	-63	-82	-101	-120	-140	-160	-180	-201	-223	-244	-265
3	Gross Territorial Peak	5023	5120	5267	5386	5519	5639	5736	5828	5907	5976	6050	6117	6180	6251	6318
4	Demand Response	-257	-260	-268	-272	-274	-277	-279	-281	-284	-286	-289	-291	-294	-297	-299
5	Net Territorial Peak	4766	4860	4999	5114	5245	5362	5457	5547	5623	5690	5761	5826	5886	5954	6019
System Capacity																
6	Existing	5282	5307	5336	5376	5421	6035	6649	6649	6649	6649	6649	6649	6649	6649	6742
	Additions:															
7	Solar Plant	25	29	40	45											
8	Peaking/Intermediate														93	93
9	Baseload					614	614									
10	Retirements															
11	Total System Capacity	5307	5336	5376	5421	6035	6649	6649	6649	6649	6649	6649	6649	6649	6742	6835
12	Firm Annual Purchase	300	225	325	425											
13	Total Production Capability	5607	5561	5701	5846	6035	6649	6649	6649	6649	6649	6649	6649	6649	6742	6835
Reserves																
14	Margin (L13-L5)	841	701	702	732	790	1287	1192	1102	1026	959	888	823	763	788	816
15	% Reserve Margin (L14/L5)	17.6%	14.4%	14.0%	14.3%	15.1%	24.0%	21.8%	19.9%	18.2%	16.9%	15.4%	14.1%	13.0%	13.2%	13.6%

Sensitivity of Nuclear Savings to Electric Load Forecast







Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years (millions)

Base Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$84	$177	$269
$15 CO2 Price	$263	$374	$468
$30 CO2 Price	$433	$562	$663

High Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$83	$180	$278
$15 CO2 Price	$276	$384	$483
$30 CO2 Price	$457	$586	$689

Low Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$82	$172	$242
$15 CO2 Price	$248	$359	$441
$30 CO2 Price	$407	$536	$629

DIRECT TESTIMONY

OF

JOSEPH M. LYNCH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2016-223-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION WITH SOUTH CAROLINA ELECTRIC & GAS COMPANY ("SCE&G" OR THE "COMPANY").

A. My name is Joseph M. Lynch and my business address is 220 Operation Way, Cayce, South Carolina. My current position with the Company is Manager of Resource Planning.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from St. Francis College in Brooklyn, New York, with a Bachelor of Science degree in mathematics. From the University of South Carolina, I received a Master of Arts degree in mathematics, a Master of Business Administration degree, and a Ph.D. in management science and finance. I was employed by SCE&G as a Senior Budget Analyst in 1977 to develop econometric models to forecast electric sales and revenue. In 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I became Supervisor of

Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and, in 1991, I was promoted to my current position of Manager of Resource Planning.

Q. WHAT ARE YOUR CURRENT DUTIES AS MANAGER OF RESOURCE PLANNING?

A. As Manager of Resource Planning, I am responsible for producing SCE&G's forecast of energy, peak demand, and revenue; for developing the Company's generation expansion plans; and for overseeing the Company's load research program.

Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION") PREVIOUSLY?

A. Yes. I have previously testified on a number of occasions before this Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the results of two studies of the cost to construct the V.C. Summer Units 2 and 3 (the "Units") under the Engineering, Procurement, and Construction Agreement ("EPC Contract") as amended by the October 27, 2015 Amendment ("Amendment"). The first study, attached as Exhibit No. __ (JML-1), is a sensitivity study that analyzes the impact of SCE&G's option to transfer the majority of the remaining EPC Contract cost to the Fixed Price category (the "Fixed Price" option) as provided by the Amendment. This study compares the cost-to-complete construction of the Units under several labor cost scenarios relative to the cost of the Fixed Price option. The second study, attached as Exhibit No. __ (JML-2), is an economic study comparing the impact on revenue requirements of continuing construction of the Units as opposed to terminating the project and building natural gas combined-cycle units instead.

THE SENSITIVITY STUDY

Q. WHAT IS THE STRUCTURE OF THE SENSITIVITY STUDY?

A. The sensitivity study analyzes the impact of labor costs on the cost-to-complete the Units. There are two primary components to labor costs: 1) the labor cost per hour, and 2) the number of hours worked (specifically in this case, the number of hours to complete construction of the Units).

Q. WHAT WAS THE LABOR COST PER HOUR USED IN THE SENSITIVITY STUDY?

A. The sensitivity study uses the labor cost per hour as of December 2015 calculated as an average in the categories of all direct craft workers, all indirect craft workers, and all field non-manual workers. SCE&G projected these three labor rates to increase by 2.9% per year over the remainder of the construction period. This scenario is the "base case" or "2.9%" scenario. The 2.9% growth rate was chosen because that is the 5-year compound growth rate of the Handy-Whitman cost index in the "All Steam & Nuclear" category for the South Atlantic.

Also, by coincidence, it is the 5-year growth rate in construction labor costs projected by our economic forecasting firm, IHS Global Insight, Inc. ("IHS"), over the period 2016-2020 averaged over several categories of labor, again, for the South Atlantic region of the country.

Q. HOW MANY DIFFERENT SCENARIOS DID SCE&G ANALYZE IN THE SENSITIVITY STUDY?

A. Exhibit No. __ (JML-1) reflects the results of my sensitivity study and shows that four different labor growth rates for the completion of construction of the Units from the current time to the Guaranteed Substantial Completion Dates ("GSCDs") under the Amendment were analyzed. The four scenarios are:

- The "no growth" or "0%" scenario represents a labor growth rate of 0%.
- The "base case" or "2.9%" scenario represents a labor growth rate of 2.9%.
- The "medium growth" or "5.0%"scenario represents a labor growth rate of 5.0%.
- The "high growth" or "7.0%"scenario represents a labor growth rate of 7.0%.

Q. WHICH LABOR RATE SCENARIO DOES SCE&G BELIEVE IS THE MOST LIKELY TO OCCUR?

A. While there is much uncertainty in projecting future labor rates, SCE&G believes the no growth scenario representing no growth in labor rates to be unrealistically optimistic. On the other extreme, the high growth scenario represents a strong growth in labor rates that is possible but similarly unlikely.

The base case scenario, corresponding to a 2.9% growth in labor rates, represents a small premium over inflation which would be reasonable under most situations. However, considering the skilled labor force required for this project and the need for night time work hours, a faster growth rate is likely. Consequently, SCE&G believes the most likely scenario for future labor rates is between the base case (2.9%) and medium growth (5.0%) scenarios.

Q. HOW DID THE SENSITIVITY STUDY REFLECT VARIATIONS IN THE NUMBER OF HOURS REQUIRED TO COMPLETE CONSTRUCTION OF THE UNITS?

A. The productivity factor ("PF") was the evaluation measure used in the sensitivity study to reflect variations in the number of hours required to complete construction of the Units. SCE&G defined the PF as the ratio of the number of actual direct craft hours worked to complete a project compared to the number of hours budgeted for that work. Six PF scenarios were studied: 1.00, 1.15, 1.25, 1.50, 1.75, and 2.00.

Q. WHAT IS THE SIGNIFICANCE OF THE PF?

A. The PF represents the efficiency with which direct craft laborers are working to complete tasks. A PF of 1.00 means that the actual number of hours required for a task was the exact number of hours budgeted for that task. For example, if a certain welding job was budgeted to take 4.0 hours, then a PF of 1.25 would mean that the welding job actually took 5.0 hours to complete (4.0 hours × 1.25 PF = 5.0 hours).

Q. SINCE THE PF APPLIES TO DIRECT CRAFT LABOR HOURS ONLY, HOW DOES THE SENSITIVITY STUDY ACCOUNT FOR INDIRECT CRAFT LABOR COSTS AND FIELD NON-MANUAL LABOR COSTS?

A. Indirect craft labor supports direct craft labor by providing such things as worker training, safety, warehouse staffing, and facilities maintenance. In order for construction to be completed by the GSCDs, SCE&G estimates that approximately 0.66 hours of indirect craft labor is required to support each hour of direct craft labor. While the actual indirect-to-direct ratio may vary from 0.66, SCE&G does not believe any variations would be significant and has kept this ratio constant for the sensitivity study. Field non-manual labor represents the cost of field engineers, quality assurance and control, administrative support, and related non-manual labor. In order for construction to be completed by the GSCDs, SCE&G estimates that approximately 0.74 hours of field non-manual labor is required to support each hour of direct craft labor. Thus, as was done with indirect craft labor, the ratio of field non-manual labor-to-direct craft labor is fixed at 0.74 for the study. Consequently, in the sensitivity study as direct craft labor hours vary so does the number of indirect labor hours and field non-manual hours as well as the associated cost for those categories of labor.

Q. ARE YOU BEING CONSERVATIVE BY SETTING THE RATIO OF INDIRECT LABOR HOURS TO DIRECT LABOR HOURS AT 0.66 AND THE RATIO FOR FIELD NON-MANUAL LABOR AT 0.74?

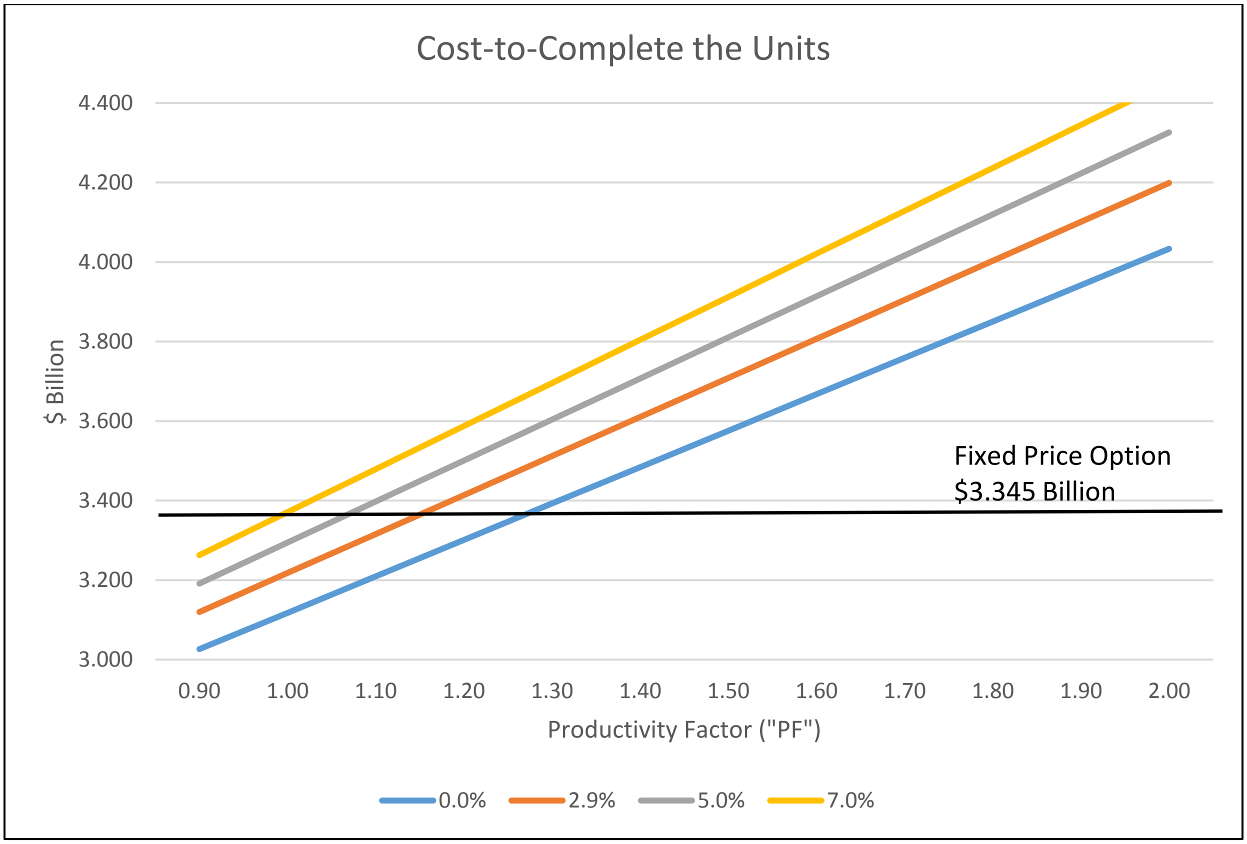
A. Yes. These are very conservative assumptions in the sense that they are low compared to historical experience with the project. If these ratios were higher, the sensitivity study would reflect that the Fixed Price option would be even more attractive. The historical average ratio of indirect-to-direct hours is 1.21 and of field non-manual-to-direct hours is 1.22. The sensitivity study assumes that Westinghouse Electric Company, LLC ("Westinghouse") and Fluor Corporation ("Fluor") will be able to significantly reduce the need for non-direct labor hours. If they are unable to do so, then the Fixed Price option becomes even more valuable to SCE&G and its customers.

Q. WHICH PF SCENARIO DOES SCE&G BELIEVE IS THE MOST LIKELY TO OCCUR?

A. The cumulative PF for this project through December 2015 is approximately 1.75. With the reorganization of the Consortium and Fluor coming onboard, there is ongoing effort to improve the PF of the project. However, SCE&G believes the most likely PF range will be between 1.50 and 2.00.

Q. CAN THE COST-TO-COMPLETE THE UNITS UNDER THE DIFFERENT SCENARIOS BE SHOWN GRAPHICALLY?

A. Yes, it can. The following graph depicts the relationship between the cost-to-complete on the vertical axis and the PF value on the horizontal axis with a reference line being added to show the cost of the Fixed Price option.



Q. WHAT CAN BE CONCLUDED FROM THIS GRAPH?

A. By noting where the reference line for the cost of the Fixed Price option crosses each of the cost-to-complete lines, the breakeven value for the PF can be observed. For example, under the 2.9% labor cost rate scenario, the cost-to-complete is represented by the second line up from the bottom (the red line). The breakeven PF value under this scenario is 1.130. This means that if Westinghouse can achieve a PF value less than 1.130 and maintain the labor rates in the base case scenario, then the Fixed Price option will increase cost to SCE&G's customers beyond the fixed price. On the other hand if the PF value is greater than 1.130, then the Fixed Price option lowers costs to SCE&G customers. The breakeven PF values for the 0%, 2.9%, 5.0%, and 7.0% scenarios are approximately 1.248, 1.130, 1.049, and 0.976 respectively.

Q. WHAT DO YOU CONCLUDE FROM THE SENSITIVITY STUDY?

A. Table A of the sensitivity study contains the results of the sensitivity study. For each combination of PF and labor cost growth rate, the table shows the cost-to-complete the Units as a percentage change to the Fixed Price option. When focusing on the most likely range of 2.9% to 5.0% in labor rate growth rates and the PF falling between 1.50 and 2.00, SCE&G estimates that the cost-to-complete the Units will be between 10.9% and 29.3% higher than the Fixed Price option. While Westinghouse may be able to make significant improvements over past performance, SCE&G believes it is in the best interest of its customers to choose the Fixed Price option and remove the price uncertainty that exists without it.

THE ECONOMIC STUDY

Q. PLEASE DESCRIBE THE METHODOLOGY USED IN THE ECONOMIC STUDY.

A. The economic study uses the same methodology and structure as the similar study presented to the Commission in 2015 in Docket No. 2015-103-E. The study is based on modeling techniques that are widely accepted in the utility industry to determine the relative cost and value of alternative approaches to meeting customers' electricity needs. The models used in the study include information about system loads, load shapes (the number of hours each year that specific load levels are reached), the available units, the ramp rates of units (the speed at which units can be brought to various levels of production), the availability factors of the units (how often units are off-line or have mechanical or environmental limits on their generating capacity), the fuel costs of units (including environmental costs of burning fuel and disposing of ash or other fuel wastes), the fuel efficiency of units (how much fuel cost is incurred per megawatt (MW) of energy produced), and the capital and operating costs of any new units including depreciation, abandonment costs, salvage cost, production tax credits and other capital related costs or benefits. Each scenario includes a different set of assumptions about one or more variables. In this case, the models dispatched the system year-by-year for 40 years to determine the relative cost to customers under each scenario considered.

Q. WHAT SCENARIOS WERE MODELED?

A. The two alternatives—completing construction of the Units compared to terminating construction of the Units and replacing them with combined-cycle gas plants—were analyzed under 27 scenarios reflecting different assumptions concerning natural gas prices, carbon dioxide ("CO_2"), emissions costs, and future load growth on our system.

Q. WHAT NATURAL GAS PRICE SCENARIOS WERE MODELED?

A. The three natural gas price scenarios modeled were the Company's base case forecast of future natural gas prices, a 50% higher gas price and a 100% higher gas price forecast.

Q. WHY WERE THESE THREE NATURAL GAS PRICE SCENARIOS CHOSEN?

A. The base case is a forecast that the Company compiles using reported New York Mercantile Exchange ("NYMEX") gas contracts. Future prices for contracts for three years are used. Beginning in year four, the forecast escalates the NYMEX price using escalation rate forecasts provided by IHS.

SCE&G uses the base case forecast as a starting point in modeling because it is simple, objective, and less subject to bias from subjective considerations. But this is also a limitation. The base case gas price may ignore important factors that require subjective judgment and are not reflected in current NYMEX prices or in escalation forecasts. In short, fossil fuel prices, especially natural gas prices, are notoriously difficult to forecast with confidence. For this reason, SCE&G usually conducts sensitivity analyses particularly with respect to future natural gas prices. Therefore, in addition to the base case gas price forecast, two other price scenarios were developed: one with 50% higher prices than the base case and a second with 100% higher prices. Higher gas prices seem very reasonable when you consider ongoing and future changes that will put upward pressure on natural gas prices. The most obvious of these changes include: 1) significantly increased demand in the power generation sector caused by the retirement of coal plants due to the Environmental Protection Agency's ("EPA") Mercury and Air Toxics Standards, or MATS, regulations and the Clean Power Plan, as well as the practical inability to add coal capacity in the future; 2) the opening of the domestic gas market to higher world prices through liquefied natural gas, or LNG, exportation; 3) the increasing regulatory scrutiny of "fracking" from an environmental point of view which will tend to increase the cost of production and reduce the supply of gas; and 4) the fact that burning natural gas emits CO_2 into the atmosphere and that the gas industry will likely come under environmental regulations similar to those crippling the coal industry. The Energy Information Administration ("EIA") in the early release of their 2016 Annual Energy Outlook provides another scenario of forecasted natural gas prices and their forecast is shown in the study as a point of comparison. The EIA forecast closely approximates SCE&G's 50% higher gas price forecast.

Q. WHAT CO_2 PRICE SCENARIOS WERE MODELED?

A. The three variations of CO_2 emission costs were $0, $15, and $30 per ton starting in 2025 and escalating at 5% per year. While the EPA's Clean Power Plan is currently subject to a judicial stay, for the purposes of this study, SCE&G assumed that the EPA's Clean Power Plan goes into effect as written. Under the scenario of completing the Units, SCE&G assumes that the State of South Carolina chooses the "rate-based" compliance option in which each electric generating unit would be required to meet an emission rate target. Under a rate-based compliance plan the new nuclear units would count towards compliance and would generate sufficient emission rate credits such that SCE&G would not be required to incur any additional CO_2 compliance costs under the Clean Power Plan. Therefore the cost of CO_2 emissions to SCE&G and its customers will be zero.

If SCE&G does not complete the Units but instead builds natural gas combined-cycle plants, then the Company assumes the State will choose the "mass-based" compliance option where an electric generating unit would be allocated a CO_2 emission cap. Under this option, SCE&G will be subject to a CO_2 emission limit and will incur costs to comply. It is uncertain what the cost of CO_2 emissions will be in the future which is the reason for studying several levels of cost.

If SCE&G does not complete the Units but instead builds natural gas combined-cycle plants, and if the State should select the rate-based compliance option (which SCE&G believes to be unlikely in this scenario), then SCE&G and its customers will be subject to CO_2 emission costs. These costs also will be substantially greater than they would have been if the State had selected the mass-based compliance option instead.

Q. WHAT LOAD GROWTH SCENARIOS WERE MODELED?

A. The three load levels considered were the Company's base case load forecast and then a low and high forecast which adjusted the forecasted load plus and minus 5%.

Q. WHAT IS THE VALUE OF INCLUDING THESE DIFFERENT LOAD GROWTH SCENARIOS?

A. The load growth scenarios show that varying load up or down 5% does not significantly affect the value of the scenarios. This is relevant because including more distributed energy resources (solar generation) or more energy efficiency gains has the same effect as reducing load growth. Our base case forecast already includes the impact of currently mandated distributed energy resources and currently planned energy efficiency investments. There may be other important reasons to increase investment in these resources. But the study shows that increasing these resources by a substantial amount does not change the value of the Units to customers in a meaningful way.

Q. WHAT WERE THE RESULTS OF THE STUDY?

A. The study shows that in all 27 scenarios, including base gas price and $0 carbon costs, the effect of cancelling the Units and switching to natural gas generation increases the costs to our customers by a significant amount. The most reasonable scenario is gas prices at base cost plus 50% and CO_2 emissions at $15 per ton. In that scenario, cancelling the Units and switching to natural gas would increase the cost to SCE&G's customers for electric service by $374 million per year on average over the 40-year planning horizon.

Q. HAVE YOU ANALYZED THE SENSITIVITY OF RESULTS TO AN INCREASE IN THE COST-TO-COMPLETE THE NUCLEAR UNITS?

A. Yes. My analysis is reflected in Exhibit No. ___ (JML-3), which shows, based on current circumstances, the amount nuclear construction costs would need to increase in order to achieve a breakeven point between completing the nuclear project and cancelling it. This study includes the updates to capital costs that are before the Commission in this proceeding. Thus, the total cost of completing the nuclear plants is assumed to be about $7.67 billion (SCE&G's share of the total cost). Exhibit No. ___ (JML-3) shows how much this cost would have to increase to make the incremental revenue requirements of cancelling the nuclear project equal to those of completing it. The most reasonable scenario reflects base gas cost plus 50% and $15 per ton CO_2. In that scenario, the future capital costs of the Units would have to increase by about $3.83 billion above current forecasts to overcome the benefit of $374 million per year from completing the Units at their current cost. Stated differently, from where we are today, the total construction cost would have to increase from $7.67 billion to about $11.50 billion to reach the breakeven point between the alternatives.

<u>CONCLUSION</u>

Q. BASED UPON THE STUDIES AND ANALYSES YOU HAVE CONDUCTED IN CONNECTION WITH THIS PROCEEDING, WHAT IS YOUR EXPERT OPINION AS TO WHETHER SCE&G SHOULD SELECT THE FIXED PRICE OPTION?

A. It is my expert opinion that the Company should exercise the Fixed Price option. As reflected in Exhibit No. ___ (JML-1), labor costs will be the principal driver of changes in what Westinghouse could charge SCE&G to complete the project. Given the most likely range of potential variables for labor productivity and labor price rates, the cost to SCE&G and its customers to complete the Units if the Fixed Price option is not chosen will be substantially greater than the Fixed Price option. Rather, the Fixed Price option will save customers between 10.9% and 29.3% of the cost of the project. Accordingly, it is my opinion that the Fixed Price option is reasonable and prudent and that the Company should select this option as being in the best interest of SCE&G and its customers.

Q. WHAT IS YOUR EXPERT OPINION AS TO WHETHER THE COMPANY SHOULD TERMINATE CONSTRUCTION OF THE UNITS AND PURSUE A NATURAL GAS STRATEGY TO MEET FUTURE GENERATION NEEDS?

A. It is my expert opinion that abandoning construction of the Units at this time and pursuing a natural gas generation strategy for base load generation needs would be imprudent and would result in significantly increased costs to customers.

The study presented in Exhibit No. ___ (JML-2) demonstrates that the Company's nuclear strategy remains the most prudent and lowest cost strategy designed to meet our customers' needs for base load generation in the future. In fact, based upon my analysis, completing construction of the Units will result in an estimated cost savings of $374 million per year for 40 years. For these reasons, in my opinion, the Company's most prudent course is to continue constructing the Units as previously authorized and approved by the Commission.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit No. __ (JML-1)

V.C. Summer Units 2 and 3: Sensitivity Analysis of Potential Price Outcomes

July 1, 2016

I. EXECUTIVE SUMMARY

Pursuant to the Engineering, Procurement and Construction Agreement (the "EPC Contact"), costs that are not subject to fixed or firm pricing are included in the Target category, and approximately 80% of the costs included in this category are for labor costs. Accordingly, labor costs will be the principal driver of changes to the amounts Westinghouse would be permitted to charge SCE&G to complete the two AP1000 units under construction in Jenkinsville, South Carolina (the "Units").

Changes in labor costs will be caused by two primary factors: 1) the productivity of Direct Craft Labor (which measures the amount of labor required to accomplish particular tasks), and 2) labor price rates (which determine the cost of that labor). This analysis models the sensitivity of project costs to variations in labor productivity ratios and labor price rates across a range of values and on a going forward basis. Not all of the scenarios modeled are equally probable; however, the range they define captures the likely range of variation in these factors.

Under a recent amendment dated October 2015 to the EPC Contract, SCE&G successfully negotiated for and secured the option to fix the price under the EPC Contract for the work needed to complete the Units ("Fixed Price" option) and thereby shift the risk of variable and increasing labor cost to the contractor. The analysis shows that, across the vast majority of the range of potential values for labor productivity and labor price rates, the Cost-to-Complete the Units if the Fixed Price option is not chosen will be greater than if the Company exercises the Fixed Price option. This is uniformly the case for all scenarios falling within the most likely range of values for labor productivity and labor price.

The data presented by this report establishes that, from a purely numerical standpoint, it is clear that exercising the Fixed Price option is in the best interest of SCE&G and its customers.

II. INTRODUCTION

A. Goals of Report

SCE&G and Santee Cooper were successful in negotiating in the 2015 EPC Amendment the option to fix the EPC Contract price for all payments made on the Units after June 30, 2015, at approximately $3.345 billion, exclusive of certain change orders, including future change orders, and changes in certain Time and Materials costs categories (the "Cost-to-Complete"). Under the Fixed Price option, the Cost-to-Complete would increase by approximately $729 million compared to the projections approved in Order No. 2015-661.[1] This amount includes the additional costs negotiated in the October 2015 EPC Contract Amendment (the "Amendment") to settle multiple claims and to obtain other valuable changes in the EPC Contract.

The NND team and the SCANA Resource Planning Department have performed this analysis in order to assess the potential risks and benefits of exercising the Fixed

[1] This fixed amount of $3.345 billion includes all of the fixed or firm and Target costs except a limited amount of work ($38.3 million) within the Time and Materials component of the EPC Contract price, which SCE&G has reason to believe it can complete for less than the current EPC Target price for this work. The $3.345 billion also would not include future change orders. While the Amendment reduces the price risk associated with future change orders, there remains a price risk that SCE&G will need to manage whether or not the Fixed Price option is exercised. The same is true of Owner's costs and Transmission costs, which are outside of the EPC Contract and therefore not subject to the Fixed Price option.

Price option from a cost perspective. Specifically, the report models 24 scenarios reflecting different values for the two primary factors driving the Cost-to-Complete. The goal is to determine under what conditions the Cost-to-Complete is likely to be more or less than $3.345 billion in the absence of additional price guarantees. This analysis also provides numerical data useful to the decision-making process. However, whether or not to exercise the Fixed Price option requires the exercise of expert business judgment in light of all the risks and uncertainties.

III. THE ASSUMPTIONS UNDERLYING THE ANALYSIS

A. Identifying the Outcomes to Be Modeled

The first step in assessing likely Costs-to-Complete is to identify the key drivers that will determine costs for the project to SCE&G. Because most other costs under the EPC Contract are already fixed or firm costs, the key drivers of future changes in the Cost-to-Complete will be labor-related costs in the Target Category. Specifically, the factors that will affect the Cost-to-Complete are Direct Craft Labor productivity, which will determine the number of labor hours (both direct and indirect) needed to complete the project, and labor price rates, which will determine the price paid for those hours.

B. The Variables Modeled

Currently, the majority of EPC Contract costs are fixed or firm. These costs include such items as design and engineering, equipment, components, and commodities. Approximately 80% of the cost categories that are subject to change, *i.e.*, the Target categories, are labor-related cost categories including Direct Craft Labor, Indirect Labor, and Field Non-Manual Labor. Therefore, labor costs in these Target cost categories are likely to drive any variation in the Cost-to-Complete the Units.

Labor productivity ratios measure the actual Direct Craft Labor hours expended to complete each scope of work compared to the labor hours budgeted to do so and changes in labor productivity ratios reflect the changes in the number of Direct Craft Labor hours needed to complete the project. Variations in the number of Direct Craft Labor hours is the principal driver of the required hours of Indirect Labor (on-site support services) and Field Non-Manual Labor (clerical, field engineering, Quality Assurance and Quality Control, supervisory and safety) needed to support Direct Craft Labor. Therefore, changes in Direct Craft productivity rates will directly impact the number of hours required to complete the project in Indirect Labor and Field Non-Manual categories.[2]

Labor rates, including benefits and overhead, are applied to the budget for labor hours to determine the estimated labor-related cost of the work. Labor rates also include cost allowances per hours worked for consumable materials, tools, personal safety equipment, and craft labor per diem.

1. Direct Labor Productivity Factor ("PF")

The first step in determining the labor cost for a particular project is to determine the units of labor required to complete the scopes of work that comprise the project. There are several steps to this process.

[2] The ratios of Indirect Labor hours and Field Non-Manual Labor hours to Direct Craft hours were held constant in this analysis to focus on the sensitivity of the outcomes to the two primary factors.

a. Units of Labor

Construction estimators use standard units of labor to estimate the cost of installing specified quantities of commodities such as concrete, rebar, pipe, valves, or conduit; terminating specified quantities of electrical lines or communication lines; or installing specified quantities of structural steel, steel flooring, stairways, or lighting. These units of labor are tied to the size and specifications of the commodities in question and the general conditions of the installation (*e.g.*, is the installation completed while on scaffolding, on the ground, aligned vertically or horizontally, etc.). The quantities of commodities are calculated as take-offs from the engineering documents for the project. Estimators then apply standard units of labor to those quantities to create an initial budget of labor hours.

b. Productivity Factors

Estimators apply PFs to the initial budget of labor hours to account for the anticipated conditions on a particular job site. A projected PF of 1.0 indicates that the work on that site is anticipated to require the standard number of labor hours. A PF of 1.10 indicates that it will require 10% more hours than the standard estimate to accomplish the work on that site. Applying PFs to the initial budget of labor hours creates a site-specific budget of labor hours for the project.

c. PFs Underlying the Current Cost Forecast

Westinghouse's estimate of the Cost-to-Complete the Units as reflected in Order No. 2015-661 was computed using a PF of 1.15 for Direct Craft Labor. Thus, Westinghouse was assuming it would take 15% more hours than originally budgeted for the Direct Craft Labor to complete the project.

If at the end of the project, 25% more Direct Craft Labor was required than was budgeted, the project will show a PF of 1.25 at completion. Similarly, if 100% more Direct Craft Labor is required than was budgeted, the PF at completion of the project will be 2.00.

The factors that could increase Direct Craft Labor productivity include such things as regulatory delays, quality issues, component delays, design changes, weather, contractor inefficiency, rework, or schedule mitigation cost. Each of these factors, if realized, will increase the labor hours needed to complete the Units. This increase will be expressed in higher labor PFs. It is therefore possible to analyze the effect of all of the important non-price factors that drive project labor costs by varying labor PFs.

d. Selecting PF Ranges for Modeling

To conduct a sensitivity analysis related to the Cost-to-Complete the Project, our team modeled Direct Craft Labor PFs of 1.00, 1.15, 1.25, 1.50, 1.75, and 2.00. These factors are measured over the remaining life of the project and, therefore, encompass any future productivity improvements made by Westinghouse and Fluor as they seek to improve the efficiency and effectiveness of their design and construction efforts. They also encompass unanticipated difficulties with the project that could increase the units of labor required.

The 1.00 PF is the PF that was included in the original cost projections for the project, chosen by the Consortium, and based on the expectation that modular construction would allow a nuclear project to achieve the productivity rates achieved in non-nuclear projects. To date, this anticipated level of efficiency has not been attained and the productivity constraints have been significant. Even so, the 1.00 PF was chosen as a lower bound to the sensitivity analysis because it is the judgment of the NND team, based on their experience with the project to date, that the chance of achieving a PF of 1.00 or less over the remaining life of the project is remote.

The 1.15 PF is the factor on which the Consortium computed the estimate of the Cost-to-Complete that is reflected in Order No. 2015-661. Based on current productivity rates, it will require a great deal of improvement for Westinghouse and Fluor to achieve a 1.15 PF going forward. This is particularly true because of the constraints of the current schedule. Mitigation likely will be required to meet current schedule commitments, which would typically involve additional labor and therefore less favorable labor productivity rates.

The 1.25, 1.50, and 1.75 PFs have been chosen to show the sensitivity of the Cost-to-Complete to movements in direct labor productivity from the floor of 1.00. The 2.00 PF is the highest leveled modeled. The 2.00 PF assumes that Westinghouse adds nearly double the amount of labor originally anticipated being required to complete the project on time. Because SCE&G believes that it is unlikely that it would require significantly more labor than represented by a 2.00 labor factor to complete the project, this PF has been chosen as the upper bound of the sensitivity analysis. Given what SCE&G knows today about the project, its leadership, and the plans for productivity improvements, SCE&G would expect the PF for the project to fall somewhere in the range of 1.50 to 2.00.

2. Labor Prices

Changes in wage and benefit rates can drive shifts in labor costs even if the number of labor hours required otherwise remains the same. To conduct a sensitivity analysis related to Direct Craft Labor, this analysis models labor cost growth rates of 0%, 2.9%, 5.0%, and 7.0% over the study period.

It is the considered judgment of the NND team and the Resource Planning Department that the likelihood of the labor cost growth rate equaling the extreme values of 0% or 7.0% is small. It is also the considered judgment of the NND team and the Resource Planning Department that it is most likely that labor cost deviations will fall between 2.9% and 5.0%. Under a "business as usual" assumption, the 2.9% growth rate would represent a reasonable forecast since it is the 5-year compound growth rate in the Handy-Whitman cost index in the "All Steam & Nuclear" category for the South Atlantic region of the country. Coincidentally, it also is the 5-year growth rate in construction labor costs projected by IHS over the period 2016-2020 averaged over several categories of labor, again, for the South Atlantic region of the country. However SCE&G believes that 2.9% may be too low because of the need for night time work which should command a premium in the market and also the tightness in the skilled labor force.

IV. RESULTS OF THE ANALYSIS

Computing the Cost-to-Complete using each possible combination of these factors resulted in data for 24 different scenarios. As presented in Table A below, these scenarios reflect the percentages by which the ultimate Cost-to-Complete the Units would exceed the cost under the Fixed Price option. Wherever the numbers are positive, customers would be expected to save that percentage of the total cost of project as a result of SCE&G exercising the Fixed Price option.

TABLE A

Sensitivity of the Project to Cost Changes
Due to Variations in Craft Labor Productivity Factors and Labor Cost Growth Rate
(Percent change in total EPC Contract cost compared to the Fixed Price option)

	Labor Cost Growth Rate (%)			
Productivity Factor	**0%**	**2.9%**	**5.0%**	**7.0%**
1.00	**-6.8**	**-3.8**	**-1.5**	**0.8**
1.15	**-2.7**	**0.6**	**3.1**	**5.6**
1.25	**0.1**	**3.5**	**6.2**	**8.9**
1.50	**6.9**	**10.9**	**13.9**	**17**
1.75	**13.7**	**18.2**	**21.6**	**25**
2.00	**20.6**	**25.5**	**29.3**	**33.1**

Raw numerical results for these scenarios are attached as **Appendix A**.

The most likely scenarios are those in the cells which give the result for PFs of 1.50, 1.75, and 2.00, and labor cost growth rates of 2.9% and 5.0%. They show that within this range of values the total Cost-to-Complete the Units would be greater than the Fixed Price option by between 10.9% and 29.3%.

V. CONCLUSION

Based on the range of values for Direct Craft Labor productivity and labor cost deviations modeled here, it is likely that the Fixed Price option will save customers between 10.9% and 29.3% of the cost of the project. Of the 24 scenarios modeled, only four show that accepting the Fixed Price option would result in higher costs to customers. Those four scenarios involved PFs or labor cost growth rates at the lower bound of the analysis, scenarios that the NND team and Resource Planning Department consider to be unlikely. While there are many other factors and benefits to be considered, the results of this sensitivity analysis provide clear numerical support for the prudency of exercising the Fixed Price option.

Appendix A: Tabular Results

Total Project Costs Due to Variations in Craft Labor Productivity Factors and Labor Cost Growth Rate ($000,000)

	Labor Cost Growth Rate			
Productivity Factor	**0%**	**2.9%**	**5.0%**	**7.0%**
1.00	**$3,118**	**$3,218**	**$3,295**	**$3,371**
1.15	**$3,255**	**$3,365**	**$3,449**	**$3,533**
1.25	**$3,347**	**$3,463**	**$3,552**	**$3,642**
1.50	**$3,576**	**$3,709**	**$3,810**	**$3,912**
1.75	**$3,805**	**$3,954**	**$4,068**	**$4,183**
2.00	**$4,033**	**$4,199**	**$4,326**	**$4,453**

Appendix B: Tabular Results

Total Project Costs Less Fixed Price Option Cost of $3,345 Million Due to Variations in Craft Labor Productivity Factors and Labor Cost Growth Rate ($000,000)

	Labor Cost Growth Rate			
Productivity Factor	0%	2.9%	5.0%	7.0%
1.00	($227)	($127)	($51)	$26
1.15	($90)	$20	$104	$188
1.25	$2	$118	$207	$297
1.50	$231	$363	$465	$567
1.75	$460	$609	$723	$838
2.00	$688	$854	$981	$1,108

Exhibit No. __ (JML-2)

Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy

July 1, 2016

SCE&G®
A SCANA COMPANY

Introduction

The purpose of this study is to determine if abandoning SCE&G's ongoing nuclear construction program and pursuing a natural gas generation strategy for base load generation needs would benefit retail customers in terms of long-run revenue requirements. SCE&G's management directed the Resource Planning Department to use current data to prepare generation cost studies comparable to those performed in 2008 that supported the original decision to construct the two nuclear units (the "Units").

SCE&G has undertaken this exercise expressly reaffirming its position that no single analysis of comparative costs underlies its choice of nuclear generation over gas-fired generation alternatives. The goal of base load generation planning is to create a diverse and flexible portfolio of generation units that can perform effectively in multiple sets of conditions over 40 years or more. No single study or series of studies is an effective substitute for informed business judgment exercised with this goal in mind.

This study calculates the incremental revenue requirements on a comparative basis for two strategies. The first is the base case which involves completing the two nuclear units which are presently under construction and scheduled to go into service in 2019 and 2020. When completed, the Units together will provide SCE&G with 1,229 MW. The second strategy is the natural gas resource strategy in which the Units are cancelled at the effective date of December 31, 2016. The Units are replaced by two combined-cycle units rated at 614 MWs each which come into service in 2019 and 2020 also.

The principal components of the study and conclusion are set forth below. The inputs to the study have been updated to reflect the most current values available.

Load Forecast and Resource Plans

To compute the revenue requirements of the two strategies over a 40-year planning horizon, the study relies on the load forecast data that were reported in summary form in SCE&G's 2016 Integrated Resource Plan. These load forecasts are updated versions of those that were used in the 2008 planning studies (the "2008 Studies") on which the original Base Load Review Act ("BLRA") order was based. Both the nuclear and gas resource strategies are measured against identical load forecasts.

Appendix 1 shows the forecast and the base case scenario resource plan. Both the nuclear capacity and the natural gas combined-cycle capacity are shown on the alternative versions of the resource plan as "base load" capacity entered on line 9 in the table shown in Appendix 1. As was the case with the 2008 Studies, the resource plans for each of the two strategies assumed that, after the base load capacity was added, additional simple-cycle natural gas-fired generation was added to meet subsequent load growth. Comparable amounts of simple-cycle generation with comparable capital cost and operating costs were added under each strategy.

Abandoning Nuclear Construction

As of December 31, 2016, SCE&G expects to have spent $4.607 billion on construction of the Units. If SCE&G were to decide to cancel the nuclear construction project, it would be subject to contractual cancellation charges, site decommissioning and stabilization expenses and other abandonment expenses in addition to the $4.607 billion that would already have been spent. SCE&G's best assessment of the amount of those cancellation expenses would be $262 million for a cancellation effective December 31, 2016. This is the cost on a 100% basis (i.e., including Santee Cooper's 45% share in expenses).

Upon cancellation of the project, SCE&G could scrap, sell or salvage certain materials, equipment and work in progress and could use the proceeds to off-set some part of the abandonment expenses. A large component of the spending to date, however, has been for site work, construction of roads, building and bridges on site, the hiring and training of personnel, design and procurement work, and other activities that do not produce salvageable materials. SCE&G estimates that of the amounts spent to date, the salvage value of materials, equipment, and work in progress would be approximately $318 million on a 100% basis. This $318 million would be netted against the gross cancellation cost of $262 million to produce an estimate of the net cancellation benefit, not considering the $4.607 billion already spent, of $56 million, again on a 100% basis. SCE&G's customers would receive the benefit of 55% of this or $31 million.

Thus, subtracting the net cancellation gain of $31 million from the $4.607 billion spent as of December 31, 2016, produces a total abandonment cost of $4.576 billion.

The model used for comparing the costs of these two strategies computes a levelized cost for capital invested that includes all relevant parameters given the nature of the asset involved. This combination of costs spent to date and additional cost to abandon the project represent a cost that must be borne by the gas resource strategy.

Benefit of a Balanced Capacity Portfolio

A significant advantage of continuing construction of the two nuclear units is that once added to SCE&G's generation fleet, the Units will produce a well-balanced capacity portfolio. The following charts show the percent distribution of capacity under a plan of continuing nuclear construction and the alternative of replacing it with natural gas-fired capacity.

CHART A

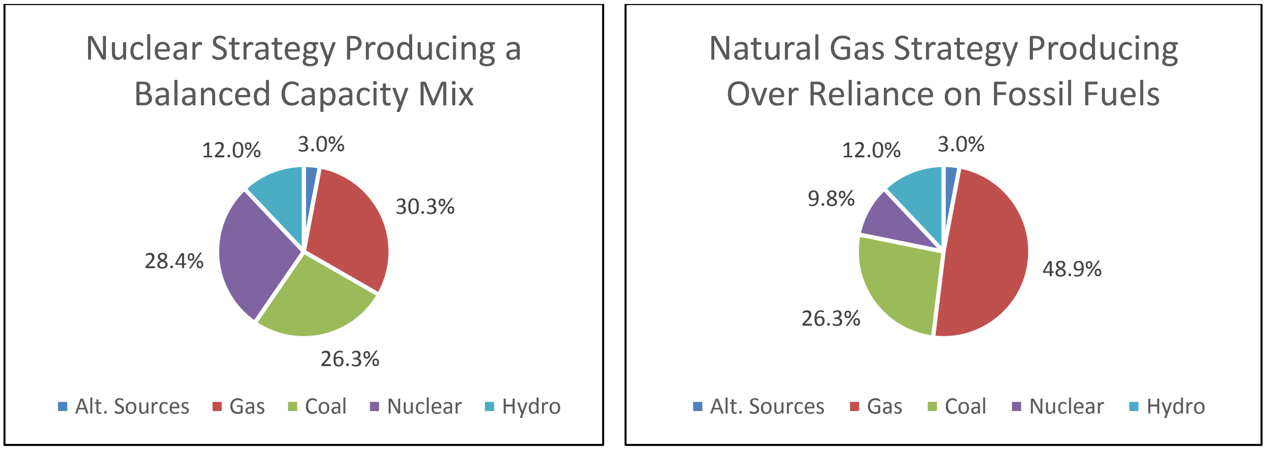


Chart A shows that the Natural Gas Strategy produces a generation system that in 2021 relies on fossil fuels for 75.2% of its generating capacity. The Nuclear Strategy creates a more balanced portfolio. Such a portfolio better protects customers from unexpectedly high costs in any one fuel source while allowing the utility to take advantage of opportunities in others.

Price of Natural Gas

Chart B shows two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration ("EIA") natural gas forecast reported in their 2016 Annual Energy Outlook ("AEO"). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor projected by the economic forecasting firm IHS Global Insight, Inc. to forecast prices beyond three years in the future. This is a methodology that SCE&G has used for a number of years to produce gas forecasts for planning studies. The value of this methodology is that it is simple and objective. However, because all forecasts of future gas prices are subject to error, SCE&G typically tests the results of these studies done using these forecasts through sensitivity analyses that model variations in gas prices.

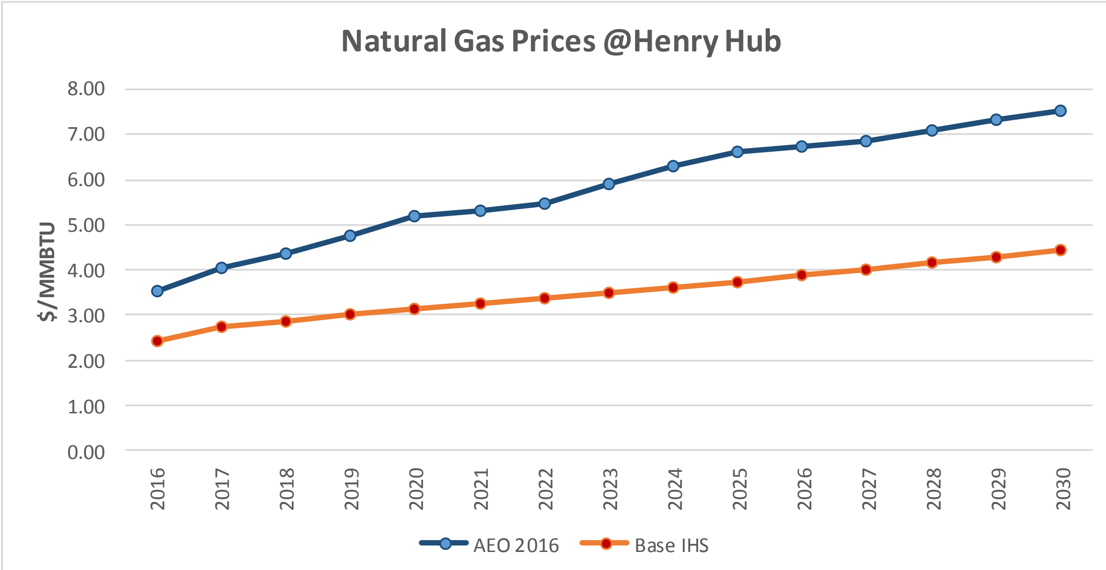
The SCE&G natural gas price forecast is the lowest of the forecasts reported on Charts B and G. It is the forecast used in these studies as the base case value for future gas prices. Charts B and C compare SCE&G baseline natural gas price forecast to the EIA's forecast that was provided in their 2016 AEO.

CHART B

	Natural Gas Price Forecasts @Henry Hub ($ per MMBTU)						
	2016	**2017**	**2018**	**2019**	**2020**	**2030**	**2035**
SCEG Baseline	2.41	2.74	2.88	2.98	3.08	4.32	5.11
EIA 2016 Forecast	3.53	4.04	4.37	4.74	5.18	7.54	8.13

Chart C graph compares SCE&G's baseline forecast to that of the EIA.

CHART C



Social Cost of Carbon

In 2009, the Obama Administration convened a group of federal agencies to establish a social cost for carbon dioxide ("CO_2") to be used in future rulemaking by federal agencies. In 2010, this interagency committee published its first social cost of carbon ("SCC"), a monetized value associated with the cost of emitting a ton of CO_2. In 2013, the interagency working group published an updated report with new estimates of the social cost of carbon.[1] Following is a copy of a table from the government's report on SCC estimates summarizing their results:

[CHART D IS ON FOLLOWING PAGE]

[1] Whitehouse Report: "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" https://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf

CHART D

Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate	5.0%	3.0%	2.5%	3.0%
Year	Avg	Avg	Avg	95th
2010	11	33	52	90
2015	12	38	58	109
2020	12	43	65	129
2025	14	48	70	144
2030	16	52	76	159
2035	19	57	81	176
2040	21	62	87	192
2045	24	66	92	206
2050	27	71	98	221

The cost of carbon emissions shown in the above table are stated in 2007 dollars. The following table restates the costs in nominal dollars assuming an inflation rate of 2% and includes the costs used in SCE&G's study.

CHART E

	Social Cost of CO2 in Nominal Dollars					SCE&G's Study	
Discount Rate	5.0%	3.0%	2.5%	3.0%			
Year	Avg	Avg	Avg	95th		$15/Ton	$30/ton
2010	12	35	55	96			
2015	14	45	68	128			
2020	16	56	84	167			
2025	20	69	100	206		$15	$30
2030	25	82	120	251		$19	$38
2035	33	99	141	306		$24	$49
2040	40	119	167	369		$31	$62
2045	51	140	195	437		$40	$80
2050	63	166	230	518		$51	$102

SCE&G's scenario of $15 per ton is very close to the lowest government estimates for SCC based on a social discount rate of 5.0%. Both of SCE&G's scenarios, the $15 and $30 scenarios, are below the SCC values recommended for government use, *i.e.*, those based on a 3.0% discount rate and are well below the high estimates based on a 2.5% social discount rate and the 95th percentile in the 3.0% discount case.

The Clean Power Plan

In August 2015 the Environmental Protection Agency ("EPA") published its Clean Power Plan under which the emissions of CO_2 by certain fossil generating plants would be regulated. The EPA established emission targets for each state covered by regulations issued under Section 111(d) of the Federal Clean Air Act and has proposed various pathways for each state to comply with those targets. Those pathways include a "rate-based" compliance plan, wherein each electric generating unit ("EGU") would be required to meet an emission rate target.

Alternatively, a state may select a "mass-based" compliance plan, in which an EGU would be allocated a CO_2 emission cap. In both the rate and mass-based plans, EGUs would have the opportunity to trade credits or allocations to assist in meeting those targets. Under a rate-based compliance plan the new nuclear units would count towards compliance and would generate sufficient emission rate credits that SCE&G would not be required to incur any additional CO_2 compliance costs under the Clean Power Plan. On the other hand, if the new nuclear units are not built then SCE&G would be subject to a CO_2 emissions limit and incur costs to comply. In this study then it was assumed under the new nuclear scenario, SCE&G's CO_2 costs would be $0 while under the natural gas scenario, the CO_2 costs would be either $0, $15, or $30 per ton.[2]

Capital Costs and Operating Costs of Natural Gas Capacity

The gas resource strategy relies on combined-cycle plants for additional base load generation. As mentioned above, both the nuclear and natural gas resource strategies add simple-cycle combustion turbines as required to meet additional capacity needs. Chart F contains the costs and heat rates assumed for these units in 2016 dollars. These inputs are based on SCE&G's ongoing monitoring of equipment and construction prices and are verified through reviews of published prices and vendor discussions. They reflect current costs to engineer, procure, and construct the assets in question.

CHART F

Gas Technology	Capacity Rating MW	Construction Cost $/KW	Heat Rate BTU/KWH	Fixed O&M Per Year	Variable O&M Per MWH
Simple-Cycle	93	$754	9,169	$708,690	$1.36
Combined-Cycle	614	$1,105	6,862	$9,009,299	$1.29

Miscellaneous Inputs

In this study, all carrying costs on capital investments are calculated including taxes, depreciation, insurance, and cost of capital as applicable to the type of asset in question. Fixed and variable O&M include current estimates of turbine maintenance costs for combined-cycle units. Nuclear production tax credits have been updated. Nuclear fuel costs are based on current forecasts of uranium prices and prices of new fuel assembly fabrication.

Scenario Analysis

In this study, the nuclear strategy and the natural gas resource strategies were studied under 27 different scenarios: three different natural gas prices, three different costs per ton of CO_2 emitted, and three different levels of load on SCE&G's system.

a. <u>Natural Gas Price Scenarios</u> - The natural gas scenarios included the base line forecast of future natural gas prices as previously discussed as well as prices reflecting a 50%

[2] On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the United States Court of Appeals for the D.C. Circuit.

and 100% increase in the base line forecast. These three gas scenarios quantify the sensitivity of the analysis to variable natural gas prices. Chart G shows the natural gas price for each scenario for several years in the forecast period, as well as EIA's projection for reference.

CHART G

Natural Gas Price Forecasts @Henry Hub ($ per MMBTU)							
	2016	**2017**	**2018**	**2019**	**2020**	**2030**	**2035**
SCEG Baseline	2.41	2.74	2.88	2.98	3.08	4.32	5.11
50% Higher Scenario	3.61	4.11	4.32	4.48	4.62	6.47	7.66
100% Higher Scenario	4.81	5.49	5.76	5.97	6.16	8.63	10.22
EIA 2016 Forecast	3.53	4.04	4.37	4.74	5.18	7.54	8.13

b. <u>CO_2 Cost Scenarios</u> – In light of current national environmental policies, it is clear that there will be a cost associated with the emissions of CO_2 in the future. It remains to be seen whether or not a fully-fledged cap and trade system will ultimately develop. In any case utilities will incur costs to lower their emissions of CO_2, certainly in the uneconomic dispatch of their generation fleets and probably through the early retirement of coal units and new investment in replacement capacity. In the present study there were three CO_2 cost scenarios used: $0, $15, and $30 per ton beginning in 2025 and escalating at 5%.

CO_2 costs at $0 per ton are not a realistic expectation for the long term. However, the $0 per ton CO_2 scenario provides a useful lower bound to test the sensitivity of the study to this input. The scenarios with $15 and $30 per ton will provide a sensitivity to the emissions cost. Both numbers are below the SCC set by the government as mentioned previously.

c. <u>Load Forecast Scenarios</u> - Three scenarios representing variations of the base case load forecast scenarios were modeled. They included the base case forecast and load forecast scenarios where the load was 5% higher and 5% lower than the base case. These higher and lower load scenarios were modeled to test the sensitivity of the analysis to variability in load due to factors such as increased economic activity or increased rates of energy conservation. The 5% plus or minus load scenarios provide for a reasonable assessment of possible variation in load on the system.

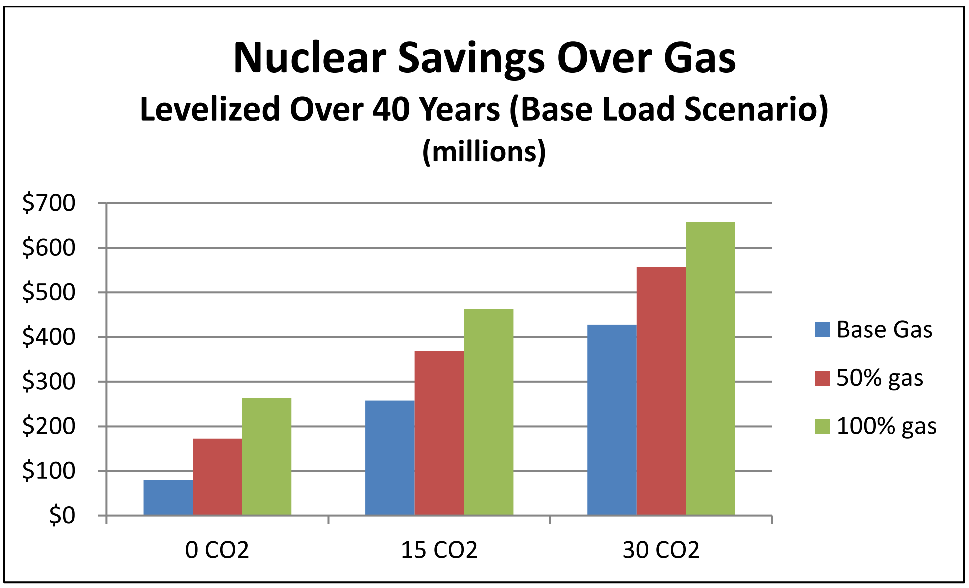
Dispatch Modeling

The results used in each of the 54 combinations of 27 scenarios and 2 generation strategies is derived from a simulation of the generation system dispatch using the PROSYM dispatch model. The PROSYM model is licensed from ABB and is widely used in the utility industry. This model determined how each generation resource on the system would be dispatched under each scenario over the 40-year planning horizon. Modeling the dispatch of the system using the PROSYM model produced both fuel cost and variable O&M costs for each scenario for each of the 40 years of the planning period. These fuel costs and variable O&M costs generated by the PROSYM model were then combined with the capital costs and other fixed costs for each scenario to determine a levelized annual cost for each of the 27 scenarios over the 40-year planning horizon.

Scenario Results

The results of the modeling are set forth below in Chart H. This chart shows the savings from continuing to construct the Units based on three sets of assumptions as to future gas prices, and based on CO_2 costs of $0, $15, and $30 evaluated against SCE&G's base case scenario for future load. SCE&G believes that the most reasonable scenario for planning purposes is the scenario that models a $15 CO_2 cost and gas prices that are 50% higher than the current SCE&G gas forecast. That analysis shows that the nuclear strategy is less costly than gas by a levelized amount of $374 million per year for 40 years.

CHART H



The numerical results of the scenarios shown in Chart H are set forth in Chart I below:

CHART I

Base Load Scenario

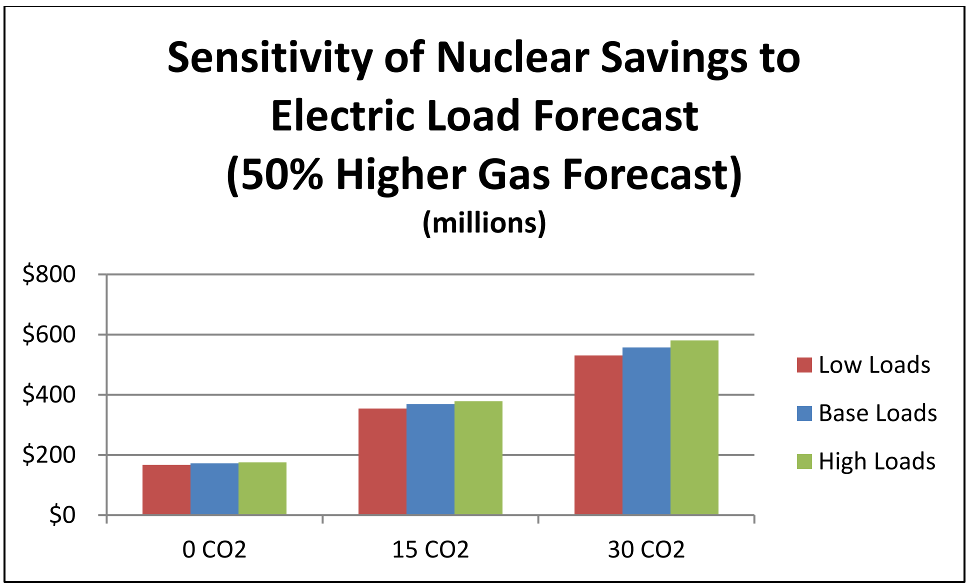
Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years (millions)			
	Base Gas	**50% Higher Gas**	**100% Higher Gas**
$0 CO2 Price	$84	$177	$269
$15 CO2 Price	$263	$374	$468
$30 CO2 Price	$433	$562	$663

This Chart highlights several critical points. First, completing the nuclear construction program is more economical than switching to a gas resource strategy across all scenarios modeled. In not one case is gas less costly than nuclear. The lowest level of nuclear advantage is a levelized annual advantage of approximately $84 million per year. This occurs using base gas price assumptions and CO_2 prices at $0 per ton. In the 2008 Studies, the $0 per ton CO_2 scenario with low gas prices resulted in nuclear being more costly than gas by $44 million.

In this series of scenarios, the nuclear strategy had the highest cost advantage over gas in the 100% Higher Gas scenario with a $30 per ton CO_2 price under the high load scenario. In that scenario, the nuclear strategy was more cost effective than the gas resource strategy by a levelized amount of $689 million per year. As mentioned above, the scenario with the set of assumptions that SCE&G believes to be most reasonable for planning purposes is 50% higher gas prices with $15 per ton CO_2 where nuclear has a cost advantage over gas of $374 million per year.

Studies were run with different assumptions as to future levels of system load to determine whether the studies' results were sensitive to changes in future electric load forecasts. Chart J shows results calculated using the base load forecast side by side with results calculated using load forecasts that have been increased by 5% and decreased by 5%. The chart shows very little variability in results based on changes in the load forecast.

CHART J



The scenario results reported on Chart J are for the 50% Higher Gas scenario. The Base Gas and 100% Higher Gas scenarios were modeled in the same way. The resulting charts are attached as Appendix 2 and the underlying data is attached as Appendix 3. They show a similar alignment of results. Collectively, these charts show that the cost advantage of the nuclear strategy over the natural gas resource strategy is consistent whether electric loads are greater or less than anticipated in the future.

There are several other inferences that can be drawn from these results of testing the nuclear and the gas resource strategies across these 27 scenarios. First, the advantage that the nuclear strategy has over the gas strategy is not dependent on load growth forecasts. Forecasts for load growth are currently very low. But even if the current load growth projections turn out to be high because of Demand Side Management, energy efficiency, or distributed or alternative generation, the nuclear advantage is not materially reduced.

Second, the study shows that the comparative economics of the nuclear and natural gas resource strategies swing widely based on gas price forecasts and future CO_2 cost assumptions. This shows that the economics of the gas resource strategy are very sensitive to swings in natural gas prices and CO_2 costs. This confirms that a resource strategy dependent of natural gas generation significantly increases SCE&G's exposure to fossil-fuel price volatility and environmental cost increases.

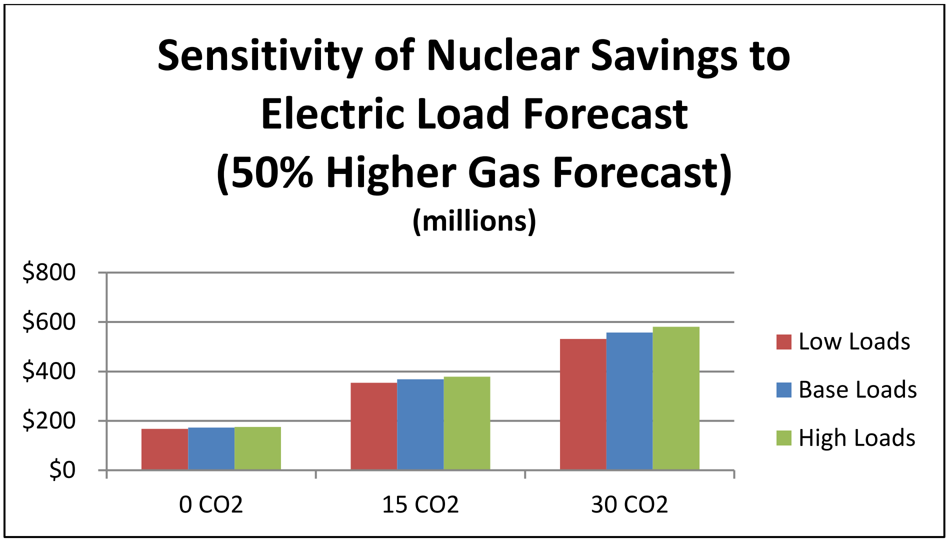
Conclusion

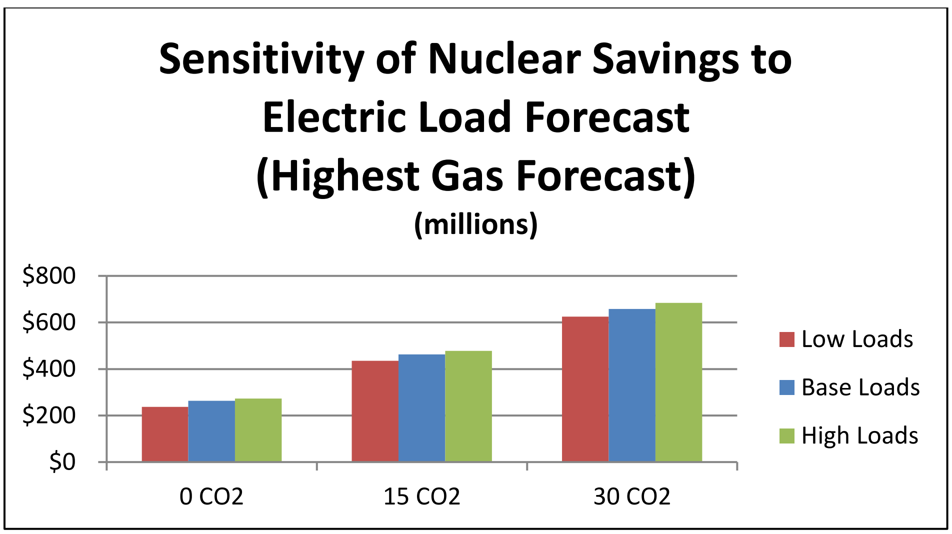
The results of this study demonstrate through the use of a full system dispatch model, run over a 40-year planning cycle, and using updated information on relevant parameters that the nuclear strategy remains the strategy best able to provide favorable results over a broad range of future operating conditions. The most reasonable estimate of the cost advantage of completing the Units is $374 million per year for 40 years.

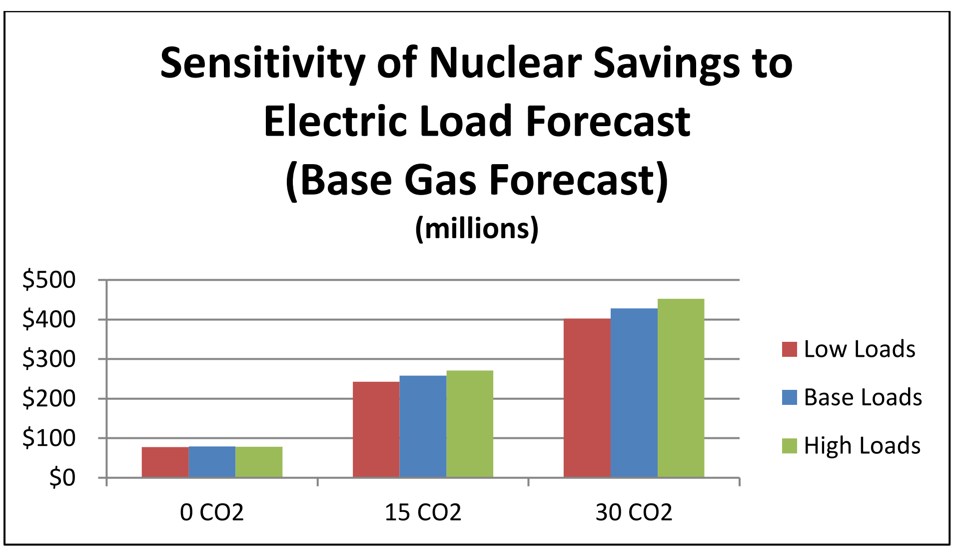
SCE&G Forecast of Summer Loads and Resources
(MW)

	YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast																
1	Baseline Trend	5031	5133	5293	5431	5582	5721	5837	5948	6047	6136	6230	6318	6403	6495	6583
2	EE Impact	-8	-13	-26	-45	-63	-82	-101	-120	-140	-160	-180	-201	-223	-244	-265
3	Gross Territorial Peak	5023	5120	5267	5386	5519	5639	5736	5828	5907	5976	6050	6117	6180	6251	6318
4	Demand Response	-257	-260	-268	-272	-274	-277	-279	-281	-284	-286	-289	-291	-294	-297	-299
5	Net Territorial Peak	4766	4860	4999	5114	5245	5362	5457	5547	5623	5690	5761	5826	5886	5954	6019
System Capacity																
6	Existing	5282	5307	5336	5376	5421	6035	6649	6649	6649	6649	6649	6649	6649	6649	6742
	Additions:															
7	Solar Plant	25	29	40	45											
8	Peaking/Intermediate														93	93
9	Baseload					614	614									
10	Retirements															
11	Total System Capacity	5307	5336	5376	5421	6035	6649	6649	6649	6649	6649	6649	6649	6649	6742	6835
12	Firm Annual Purchase	300	225	325	425											
13	Total Production Capability	5607	5561	5701	5846	6035	6649	6649	6649	6649	6649	6649	6649	6649	6742	6835
Reserves																
14	Margin (L13-L5)	841	701	702	732	790	1287	1192	1102	1026	959	888	823	763	788	816
15	% Reserve Margin (L14/L5)	17.6%	14.4%	14.0%	14.3%	15.1%	24.0%	21.8%	19.9%	18.2%	16.9%	15.4%	14.1%	13.0%	13.2%	13.6%

Sensitivity of Nuclear Savings to Electric Load Forecast







Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years (millions)

Base Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO2 Price	\$84	\$177	\$269
\$15 CO2 Price	\$263	\$374	\$468
\$30 CO2 Price	\$433	\$562	\$663

High Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO2 Price	\$83	\$180	\$278
\$15 CO2 Price	\$276	\$384	\$483
\$30 CO2 Price	\$457	\$586	\$689

Low Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO2 Price	\$82	\$172	\$242
\$15 CO2 Price	\$248	\$359	\$441
\$30 CO2 Price	\$407	\$536	\$629

Exhibit No. __ (JML-3)

Increase in Capital Costs of Nuclear Strategy Needed for Breakeven with Gas Strategy Based on Present Worth of Incremental Revenue Requirements Over 40 Years
(millions)

Base Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO_2 Price	\$860	\$1,815	\$2,752
\$15 CO_2 Price	\$2,691	\$3,827	\$4,790
\$30 CO_2 Price	\$4,435	\$5,761	\$6,792

High Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO_2 Price	\$852	\$1,849	\$2,849
\$15 CO_2 Price	\$2,825	\$3,932	\$4,950
\$30 CO_2 Price	\$4,684	\$6,004	\$7,062

Low Load Scenario

	Base Gas	50% Higher Gas	100% Higher Gas
\$0 CO_2 Price	\$841	\$1,763	\$2,483
\$15 CO_2 Price	\$2,539	\$3,679	\$4,513
\$30 CO_2 Price	\$4,169	\$5,492	\$6,448

V.C. Summer Units 2 and 3: Sensitivity Analysis of Potential Price Outcomes

July 1, 2016

I. EXECUTIVE SUMMARY

Pursuant to the Engineering, Procurement and Construction Agreement (the "EPC Contact"), costs that are not subject to fixed or firm pricing are included in the Target category, and approximately 80% of the costs included in this category are for labor costs. Accordingly, labor costs will be the principal driver of changes to the amounts Westinghouse would be permitted to charge SCE&G to complete the two AP1000 units under construction in Jenkinsville, South Carolina (the "Units").

Changes in labor costs will be caused by two primary factors: 1) the productivity of Direct Craft Labor (which measures the amount of labor required to accomplish particular tasks), and 2) labor price rates (which determine the cost of that labor). This analysis models the sensitivity of project costs to variations in labor productivity ratios and labor price rates across a range of values and on a going forward basis. Not all of the scenarios modeled are equally probable; however, the range they define captures the likely range of variation in these factors.

Under a recent amendment dated October 2015 to the EPC Contract, SCE&G successfully negotiated for and secured the option to fix the price under the EPC Contract for the work needed to complete the Units ("Fixed Price" option) and thereby shift the risk of variable and increasing labor cost to the contractor. The analysis shows that, across the vast majority of the range of potential values for labor productivity and labor price rates, the Cost-to-Complete the Units if the Fixed Price option is not chosen will be greater than if the Company exercises the Fixed Price option. This is uniformly the case for all scenarios falling within the most likely range of values for labor productivity and labor price.

The data presented by this report establishes that, from a purely numerical standpoint, it is clear that exercising the Fixed Price option is in the best interest of SCE&G and its customers.

II. INTRODUCTION

A. Goals of Report

SCE&G and Santee Cooper were successful in negotiating in the 2015 EPC Amendment the option to fix the EPC Contract price for all payments made on the Units after June 30, 2015, at approximately $3.345 billion, exclusive of certain change orders, including future change orders, and changes in certain Time and Materials costs categories (the "Cost-to-Complete"). Under the Fixed Price option, the Cost-to-Complete would increase by approximately $729 million compared to the projections approved in Order No. 2015-661.[1] This amount includes the additional costs negotiated in the October 2015 EPC Contract Amendment (the "Amendment") to settle multiple claims and to obtain other valuable changes in the EPC Contract.

The NND team and the SCANA Resource Planning Department have performed this analysis in order to assess the potential risks and benefits of exercising the Fixed

[1] This fixed amount of $3.345 billion includes all of the fixed or firm and Target costs except a limited amount of work ($38.3 million) within the Time and Materials component of the EPC Contract price, which SCE&G has reason to believe it can complete for less than the current EPC Target price for this work. The $3.345 billion also would not include future change orders. While the Amendment reduces the price risk associated with future change orders, there remains a price risk that SCE&G will need to manage whether or not the Fixed Price option is exercised. The same is true of Owner's costs and Transmission costs, which are outside of the EPC Contract and therefore not subject to the Fixed Price option.

Price option from a cost perspective. Specifically, the report models 24 scenarios reflecting different values for the two primary factors driving the Cost-to-Complete. The goal is to determine under what conditions the Cost-to-Complete is likely to be more or less than $3.345 billion in the absence of additional price guarantees. This analysis also provides numerical data useful to the decision-making process. However, whether or not to exercise the Fixed Price option requires the exercise of expert business judgment in light of all the risks and uncertainties.

III. THE ASSUMPTIONS UNDERLYING THE ANALYSIS

A. Identifying the Outcomes to Be Modeled

The first step in assessing likely Costs-to-Complete is to identify the key drivers that will determine costs for the project to SCE&G. Because most other costs under the EPC Contract are already fixed or firm costs, the key drivers of future changes in the Cost-to-Complete will be labor-related costs in the Target Category. Specifically, the factors that will affect the Cost-to-Complete are Direct Craft Labor productivity, which will determine the number of labor hours (both direct and indirect) needed to complete the project, and labor price rates, which will determine the price paid for those hours.

B. The Variables Modeled

Currently, the majority of EPC Contract costs are fixed or firm. These costs include such items as design and engineering, equipment, components, and commodities. Approximately 80% of the cost categories that are subject to change, *i.e.*, the Target categories, are labor-related cost categories including Direct Craft Labor, Indirect Labor, and Field Non-Manual Labor. Therefore, labor costs in these Target cost categories are likely to drive any variation in the Cost-to-Complete the Units.

Labor productivity ratios measure the actual Direct Craft Labor hours expended to complete each scope of work compared to the labor hours budgeted to do so and changes in labor productivity ratios reflect the changes in the number of Direct Craft Labor hours needed to complete the project. Variations in the number of Direct Craft Labor hours is the principal driver of the required hours of Indirect Labor (on-site support services) and Field Non-Manual Labor (clerical, field engineering, Quality Assurance and Quality Control, supervisory and safety) needed to support Direct Craft Labor. Therefore, changes in Direct Craft productivity rates will directly impact the number of hours required to complete the project in Indirect Labor and Field Non-Manual categories.[2]

Labor rates, including benefits and overhead, are applied to the budget for labor hours to determine the estimated labor-related cost of the work. Labor rates also include cost allowances per hours worked for consumable materials, tools, personal safety equipment, and craft labor per diem.

1. Direct Labor Productivity Factor ("PF")

The first step in determining the labor cost for a particular project is to determine the units of labor required to complete the scopes of work that comprise the project. There are several steps to this process.

[2] The ratios of Indirect Labor hours and Field Non-Manual Labor hours to Direct Craft hours were held constant in this analysis to focus on the sensitivity of the outcomes to the two primary factors.

a. Units of Labor

Construction estimators use standard units of labor to estimate the cost of installing specified quantities of commodities such as concrete, rebar, pipe, valves, or conduit; terminating specified quantities of electrical lines or communication lines; or installing specified quantities of structural steel, steel flooring, stairways, or lighting. These units of labor are tied to the size and specifications of the commodities in question and the general conditions of the installation (*e.g.*, is the installation completed while on scaffolding, on the ground, aligned vertically or horizontally, etc.). The quantities of commodities are calculated as take-offs from the engineering documents for the project. Estimators then apply standard units of labor to those quantities to create an initial budget of labor hours.

b. Productivity Factors

Estimators apply PFs to the initial budget of labor hours to account for the anticipated conditions on a particular job site. A projected PF of 1.0 indicates that the work on that site is anticipated to require the standard number of labor hours. A PF of 1.10 indicates that it will require 10% more hours than the standard estimate to accomplish the work on that site. Applying PFs to the initial budget of labor hours creates a site-specific budget of labor hours for the project.

c. PFs Underlying the Current Cost Forecast

Westinghouse's estimate of the Cost-to-Complete the Units as reflected in Order No. 2015-661 was computed using a PF of 1.15 for Direct Craft Labor. Thus, Westinghouse was assuming it would take 15% more hours than originally budgeted for the Direct Craft Labor to complete the project.

If at the end of the project, 25% more Direct Craft Labor was required than was budgeted, the project will show a PF of 1.25 at completion. Similarly, if 100% more Direct Craft Labor is required than was budgeted, the PF at completion of the project will be 2.00.

The factors that could increase Direct Craft Labor productivity include such things as regulatory delays, quality issues, component delays, design changes, weather, contractor inefficiency, rework, or schedule mitigation cost. Each of these factors, if realized, will increase the labor hours needed to complete the Units. This increase will be expressed in higher labor PFs. It is therefore possible to analyze the effect of all of the important non-price factors that drive project labor costs by varying labor PFs.

d. Selecting PF Ranges for Modeling

To conduct a sensitivity analysis related to the Cost-to-Complete the Project, our team modeled Direct Craft Labor PFs of 1.00, 1.15, 1.25, 1.50, 1.75, and 2.00. These factors are measured over the remaining life of the project and, therefore, encompass any future productivity improvements made by Westinghouse and Fluor as they seek to improve the efficiency and effectiveness of their design and construction efforts. They also encompass unanticipated difficulties with the project that could increase the units of labor required.

The 1.00 PF is the PF that was included in the original cost projections for the project, chosen by the Consortium, and based on the expectation that modular construction would allow a nuclear project to achieve the productivity rates achieved in non-nuclear projects. To date, this anticipated level of efficiency has not been attained and the productivity constraints have been significant. Even so, the 1.00 PF was chosen as a lower bound to the sensitivity analysis because it is the judgment of the NND team, based on their experience with the project to date, that the chance of achieving a PF of 1.00 or less over the remaining life of the project is remote.

The 1.15 PF is the factor on which the Consortium computed the estimate of the Cost-to-Complete that is reflected in Order No. 2015-661. Based on current productivity rates, it will require a great deal of improvement for Westinghouse and Fluor to achieve a 1.15 PF going forward. This is particularly true because of the constraints of the current schedule. Mitigation likely will be required to meet current schedule commitments, which would typically involve additional labor and therefore less favorable labor productivity rates.

The 1.25, 1.50, and 1.75 PFs have been chosen to show the sensitivity of the Cost-to-Complete to movements in direct labor productivity from the floor of 1.00. The 2.00 PF is the highest leveled modeled. The 2.00 PF assumes that Westinghouse adds nearly double the amount of labor originally anticipated being required to complete the project on time. Because SCE&G believes that it is unlikely that it would require significantly more labor than represented by a 2.00 labor factor to complete the project, this PF has been chosen as the upper bound of the sensitivity analysis. Given what SCE&G knows today about the project, its leadership, and the plans for productivity improvements, SCE&G would expect the PF for the project to fall somewhere in the range of 1.50 to 2.00.

2. Labor Prices

Changes in wage and benefit rates can drive shifts in labor costs even if the number of labor hours required otherwise remains the same. To conduct a sensitivity analysis related to Direct Craft Labor, this analysis models labor cost growth rates of 0%, 2.9%, 5.0%, and 7.0% over the study period.

It is the considered judgment of the NND team and the Resource Planning Department that the likelihood of the labor cost growth rate equaling the extreme values of 0% or 7.0% is small. It is also the considered judgment of the NND team and the Resource Planning Department that it is most likely that labor cost deviations will fall between 2.9% and 5.0%. Under a "business as usual" assumption, the 2.9% growth rate would represent a reasonable forecast since it is the 5-year compound growth rate in the Handy-Whitman cost index in the "All Steam & Nuclear" category for the South Atlantic region of the country. Coincidentally, it also is the 5-year growth rate in construction labor costs projected by IHS over the period 2016-2020 averaged over several categories of labor, again, for the South Atlantic region of the country. However SCE&G believes that 2.9% may be too low because of the need for night time work which should command a premium in the market and also the tightness in the skilled labor force.

IV. RESULTS OF THE ANALYSIS

Computing the Cost-to-Complete using each possible combination of these factors resulted in data for 24 different scenarios. As presented in Table A below, these scenarios reflect the percentages by which the ultimate Cost-to-Complete the Units would exceed the cost under the Fixed Price option. Wherever the numbers are positive, customers would be expected to save that percentage of the total cost of project as a result of SCE&G exercising the Fixed Price option.

TABLE A

Sensitivity of the Project to Cost Changes
Due to Variations in Craft Labor Productivity Factors and Labor Cost Growth Rate
(Percent change in total EPC Contract cost compared to the Fixed Price option)

	Labor Cost Growth Rate (%)			
Productivity Factor	**0%**	**2.9%**	**5.0%**	**7.0%**
1.00	**-6.8**	**-3.8**	**-1.5**	**0.8**
1.15	**-2.7**	**0.6**	**3.1**	**5.6**
1.25	**0.1**	**3.5**	**6.2**	**8.9**
1.50	**6.9**	**10.9**	**13.9**	**17**
1.75	**13.7**	**18.2**	**21.6**	**25**
2.00	**20.6**	**25.5**	**29.3**	**33.1**

Raw numerical results for these scenarios are attached as **Appendix A**.

The most likely scenarios are those in the cells which give the result for PFs of 1.50, 1.75, and 2.00, and labor cost growth rates of 2.9% and 5.0%. They show that within this range of values the total Cost-to-Complete the Units would be greater than the Fixed Price option by between 10.9% and 29.3%.

V. CONCLUSION

Based on the range of values for Direct Craft Labor productivity and labor cost deviations modeled here, it is likely that the Fixed Price option will save customers between 10.9% and 29.3% of the cost of the project. Of the 24 scenarios modeled, only four show that accepting the Fixed Price option would result in higher costs to customers. Those four scenarios involved PFs or labor cost growth rates at the lower bound of the analysis, scenarios that the NND team and Resource Planning Department consider to be unlikely. While there are many other factors and benefits to be considered, the results of this sensitivity analysis provide clear numerical support for the prudency of exercising the Fixed Price option.

Appendix A: Tabular Results

Total Project Costs Due to Variations in Craft Labor Productivity Factors and Labor Cost Growth Rate ($000,000)

	Labor Cost Growth Rate			
Productivity Factor	**0%**	**2.9%**	**5.0%**	**7.0%**
1.00	**$3,118**	**$3,218**	**$3,295**	**$3,371**
1.15	**$3,255**	**$3,365**	**$3,449**	**$3,533**
1.25	**$3,347**	**$3,463**	**$3,552**	**$3,642**
1.50	**$3,576**	**$3,709**	**$3,810**	**$3,912**
1.75	**$3,805**	**$3,954**	**$4,068**	**$4,183**
2.00	**$4,033**	**$4,199**	**$4,326**	**$4,453**

Appendix B: Tabular Results

Total Project Costs Less Fixed Price Option Cost of $3,345 Million Due to Variations in Craft Labor Productivity Factors and Labor Cost Growth Rate ($000,000)

	Labor Cost Growth Rate			
Productivity Factor	**0%**	**2.9%**	**5.0%**	**7.0%**
1.00	**($227)**	**($127)**	**($51)**	**$26**
1.15	**($90)**	**$20**	**$104**	**$188**
1.25	**$2**	**$118**	**$207**	**$297**
1.50	**$231**	**$363**	**$465**	**$567**
1.75	**$460**	**$609**	**$723**	**$838**
2.00	**$688**	**$854**	**$981**	**$1,108**

Benefit of 2 Nuclear @55% Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years ($MM)

Without Production Tax Credits

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	($286)	($182)	($80)
$15 CO_2 Price	($69)	$52	$160
$30 CO_2 Price	$135	$276	$396

With Production Tax Credits

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	($208)	($104)	($2)
$15 CO_2 Price	$10	$131	$239
$30 CO_2 Price	$214	$355	$475

Benefit of 1 Nuclear @55% Strategy over the Gas Strategy
Levelized Present Worth of Change in Revenue Requirements Over 40 Years
($MM)

Without Production Tax Credits

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	($197)	($145)	($90)
$15 CO_2 Price	$11	$84	$149
$30 CO_2 Price	$204	$293	$373

With Production Tax Credits

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	($155)	($102)	($47)
$15 CO_2 Price	$54	$126	$191
$30 CO_2 Price	$246	$335	$415

Benefit of 2 Nuclear @55% Strategy over 1 Nuclear @55%
Levelized Present Worth of Change in Revenue Requirements Over 40 Years
($MM)

Without Production Tax Credits

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	($89)	($38)	$9
$15 CO_2 Price	($80)	($31)	$12
$30 CO_2 Price	($68)	($16)	$23

With Production Tax Credits

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	($53)	($1)	$46
$15 CO_2 Price	($44)	$5	$48
$30 CO_2 Price	($32)	$20	$60

Benefit of 1 Nuclear @100% Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years ($MM)

Without Production Tax Credits

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	($424)	($327)	($232)
$15 CO_2 Price	($214)	($99)	$5
$30 CO_2 Price	($21)	$111	$231

With Production Tax Credits

	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO_2 Price	($347)	($250)	($155)
$15 CO_2 Price	($137)	($22)	$82
$30 CO_2 Price	$56	$188	$308